BEFORE THE
CALIFORNIA ENERGY COMMISSION (CEC)

In the matter of	)
	) Docket No. 13-IEP-1C
2013 Integrated Energy	)
Policy Report	)
(2013 IEPR)	)

IEPR LEAD COMMISSIONER WORKSHOP

REVISED ELECTRICITY AND NATURAL GAS DEMAND FORECASTS
2014-2024

Cal/EPA Headquarters Building
Byron Sher Auditorium
1001 "I" Street, Second Floor
Sacramento, California 95814

Tuesday, October 1, 2013
10:00 A.M.

Reported by:
Kent Odell

APPEARANCES

COMMISSIONERS PRESENT:

Robert Weisenmiller
Andrew McAllister

STAFF PRESENT:

Heather Raitt, CEC
Chris Kavalec, CEC, Demand Analysis Office, Electricity Supply Analysis Division
Malachi Weng-Gutierrez, CEC, Demand Analysis Office, Electricity Supply Analysis Division
Asish Gautam, CEC, Demand Analysis Office, Electricity Supply Analysis Division
Tim Olson, CEC, Transportation Energy Office, Fuels and Transportation Division
Nick Fugate, CEC, Demand Analysis Office, Electricity Supply Analysis Division

ALSO PRESENT:

Dan Cayan, Scripps Institute of Oceanography
Analisa Bevan, Air Resources Board
Floyd Kneipe, Navigant
Simon Baker, California Public Utilities Commission, Energy Division
Sierra Martinez, Natural Resources Defense Council, California Energy Projects
Sasha Cole, CA Public Utilities Commission, Energy Division
Anna Wong, California Air Resources Board
Tim Vonder, San Diego Gas & Electric Company
Hongyan Sheng, Southern California Edison
Ipek Connolly, Pacific Gas & Electric Company, Load Forecasting Group
Nate Toyama, Sacramento Municipal Utilities District

PUBLIC COMMENT

Bill Monsen, MRW and Associates, representing IEP
Lorenzo Kristov, Independent System Operator

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P R O C E E D I N G S

OCTOBER 1, 2013 10:09 A.M.

MS. RAITT: Okay, good morning. Welcome to today's IEPR workshop on the Revised Electricity and Natural Gas Demand Forecasts. I'm Heather Raitt, the Lead for the IEPR.

First, a few housekeeping items. Restrooms are out the doors and to the left and there's a snack room on the first floor. Today's workshop is being broadcast through our WebEx Conferencing System and parties are to be aware that you're being recorded. We'll post the audio recording on the Commission's website in a couple of days with a transcript in about three weeks.

Today's agenda is very full. The morning will begin with a presentation by staff on the forecast results, followed by a presentation from Scripps Institute of Oceanography, and then presentations from staff on electricity and natural gas rate reductions, distributed generation impacts, and additional and achievable energy savings.

We will then provide a brief opportunity for public comments before breaking lunch at about 12:30. If possible, please hold your comments until the end of the day, but if your schedule does not allow for that, we will have, as I said, a brief comment period before lunch.

After lunch, we will hear from staff of the Energy Commission and the Air Resources Board on an Electric Vehicle forecast, and then we will hear from the Energy Commission staff on forecasts for the largest utility Planning Areas with responses from the utilities. We will then take public comments; we are asking parties to limit their comments to three minutes during the public comment period. We'll take comments first from those in the room, then followed by those participating by WebEx, and finally from those who are phone-in only. For those in the room who would like to make comments, please fill out a blue card and give it to me, or to Lynette, and when it's your turn to speak, please come to the podium and we have a microphone there, or here, and speak into the microphone. It's also helpful to give your business card to the Court Reporter. For WebEx participants, we'll use the chat function to tell our WebEx coordinator that you want to ask a question or make a comment during the public comment period, and we'll either relay your question or open your line at the appropriate time. For phone-in participants, we'll open lines after we've taken comments from in-person and WebEx participants. And as a reminder, please mute your phone.

Written comments on today's topics are due at the close of business on October 15th. Information about providing comments is provided in the notice, which is on the table with the handouts and also posted on our website. And with that, I'll turn it over to the Commissioners for opening comments. Thank you.

COMMISSIONER MCALLISTER: Great. Thank you, Heather. I'm Andrew McAllister, the Lead Commission on the 2013 IEPR. I really want to thank EPA and the ARB for having us here today. It turns out I think we could have done it over at our building, but we really wanted to make sure that we were going to have (indiscernible) -- oh, oh, except for the AV, it's great here (laughing). No, but this is a terrific space to have this discussion.

Iterations of analysis and interaction

with stakeholders is really key for the forecasting process, for getting to an end result that we can hopefully have some great consensus around, but also a lot of richness is in the dialogue itself and I think our team at the Energy Commission and the State, in general, benefit from that process, and so we're going to see the latest update here where we're really getting ready for prime time, so I'm excited to see the update.

I want to thank Heather and Lynette and the rest of the IEPR team, all the individual chapter authors on the forecast, many many people involved on the electricity and interacting with their colleagues across the agency and with the Natural Gas section.

And so really what we're going to hear today represents a very heavy lift, and particular we're in a heavy lifting period for the IEPR document itself and it's really getting, I think, in good form to be released here in the next few days, so you'll all get to see that here in the very near future.

A lot of questions this year -- always -- but in particular this year, you know, the role of energy efficiency and continuing the dialogue across agencies to figure out how much future energy efficiency we build into the forecasts, and that's really critical and is going to continue to be so going forward.

We've had a downturn and economies rebounding, and how that's going to play out with electricity demand across the state in the future -- big questions. How markets are going to uptake all these new technologies that are coming into the marketplace, big questions for energy demand going forward. So the sort of high, medium and low demand scenarios for the forecasts, I think, capture that uncertainty well and, as we track going forward, I think it's going to be really interesting to see how things unfold.

So again, I want to thank staff for the huge amount of work that's gone into this, I want to thank all of you who have been here steadfastly throughout the process, and appreciate your coming to this update, as well, for those of you here in the room and on the Web. So with that, I'll pass it over to Chair Weisenmiller.

CHAIRMAN WEISENMILLER: Yeah, and certainly want to thank folks for being here today and, as Commissioner McAllister said, we're sort of getting to that moment of the IEPR where staff is on the one hand trying to push out a report, and on the other hand we're trying to deal with the last remaining issues. And obviously the Demand Forecast is one of the last remaining issues; it's a very important part of the IEPR, particularly looking at the energy efficiency part, certainly it's been a pretty good effort so far this year, it's probably time that people thought about what we need to be thinking about doing next year, you know, that obviously in this period of time we have not managed to get everything nailed down, really resolved all the things we want to resolve, so it's time to start doing what we can here, wrapping it up, move on, but at the same time have a pretty aggressive agenda on making progress next year. So with that, let's start the presentations.

MS. RAITT: Our first speaker is Chris Kavalec.

MR. KAVALEC: Good morning. I'm Chris

Kavalec from the Energy Commission's Demand Analysis Office. We are presenting our revised forecasts here today and we will obviously be taking comments because there is some opportunity to make adjustments to the forecasts before it becomes a final version that is submitted for adoption in December.

So this is our California Energy Demand or CED 2013 Revised Baseline Forecast for Electricity and Natural Gas. And a couple things about terminology: the traditional forecasts that we do that includes only committed efficiency savings, that is, savings from initiatives that are either already implemented, or have firm funding, and have been approved and finalized, that version of the forecast we're referring to as the "baseline forecast" as opposed to a forecast which incorporates additional achievable energy efficiency, that is, efficiency from initiatives that don't have final approval for firm funding, yet are likely to occur, for example, future updates of the Title 24 standards. But the version of the forecast with that adjustment made we're referring to as the "adjusted forecast."

This adjusted forecast will then be used by the CPUC during their Long Term Procurement Process and they will make additional adjustments, for example, possibly for distributed generation, or demand response. That version of the forecast we refer to as the "managed forecast," okay, so we have baseline forecast and adjusted forecast we're talking about today, and then managed forecast for planning purposes.

Okay, today in addition to my presentation, we're going to have Dan Cayan from the Scripps Institute of Oceanography talk about the possible impacts of climate change on the relationship between extreme and average temperatures, which has implications for planning; we're going to present our revised energy prices for electricity and natural gas; we'll have a presentation on self-generation featuring a model we've used for the first time for commercial photovoltaics; then I'll be making a presentation on the additional achievable energy efficiency and how the baseline forecasts look when adjusted for this

AAEE savings.

Our Transportation Energy Office is busy working on a new Electric and Natural Gas Vehicle Forecast, as well as some additional impacts from electrification. That hasn't been completed yet, but they'll be here to give us a status update on how that work is going. Hopefully, we'll be able to incorporate these forecasts into the final version of our forecasts for adoption in December.

And as usual, we will provide our Planning Area forecasts. The additional achievable energy efficiency is meant to be applied at the service territory level. In the case of Southern California Edison, PG&E, and Socal Gas, the service territory is a subset of the Planning Areas; therefore, for those three Planning Areas, we'll be presenting in addition to Planning Area results individual service territory results, and those service territory results adjusted by the additional achievable energy efficiency.

Okay, in my presentation I'm going to be talking a little bit about methodology. Most of you are somewhat familiar with the way that we forecast, but for those who aren't, just a little bit of information. I'll be providing some statewide results and comparing those statewide results to our previous forecasts, the last adopted forecasts in 2011, and our preliminary forecasts that we released in May of this year. The efficiency that is incorporated in the baseline forecast, committed efficiency, I'll be comparing this forecast with an econometric forecast that we do separately, and as a lead-in to our next presentation, I'll be talking about how climate change is incorporated into the forecast.

So when we forecast for electricity, we forecast for eight different Planning Areas, listed here. And as I mentioned, for PG&E and Southern California Edison, we'll be presenting both Planning Area and service territory results.

Natural gas Planning Areas, Southern California Gas, Planning Area and service territory results.

And for our 2013 forecasts, both the preliminary and the revised, which we're presenting today, we also provide results at the climate zone level. We have 16 forecasts in climate zones in California, three of the Planning Areas have multiple climate zones, PG&E has five, Southern California Edison has four, and LADWP has two. And we make this distinction of climate zones, too, because weather sensitive usage is very important when you're talking about the coast versus inland, or north versus south.

So our approach includes individual sector models for the sectors listed here for consumption, residential, commercial and industrial, we have end use models, and "end use" means we're starting at the level of average usage per appliance by type of appliance. We also have disaggregated econometric and trend models for the agricultural sector and for transportation communications and utilities, or TCU and street lighting. Consumption results from the individual sector models are sent to our summary model where weather adjustments are applied and the model results are calibrated to actual consumption.

Then the summary model provides input

into our peak model where load shapes are applied and we develop an estimated peak for each Planning Area, for each year.

And we also have predictive models for self-generation, residential photovoltaic, residential solar hot water, commercial PV, and commercial CHP.

As I mentioned, we also do a separate forecast using econometric models, more aggregate models for each sector, so we have econometric models for all sectors except for TCU in the case of gas, where the data was a little erratic and where we weren't able to fit a reasonable regression into that data.

We also have an econometric model, a peak model, and we use these models as a point of comparison to our end use model results, and we use some of the results from these econometric models in our end use models; for example, price elasticities estimated in the econometric models are used in the end use models.

Okay, compared to our last adopted forecast in 2011, here are some of the changes and improvements we've made. We have a new industrial model. We had been relying on what's called the inform industrial model developed by EPRI in the '90s, but that model is no longer supported and we didn't have the executable code for it, so we decided to build a new model from the ground up with a similar methodology, and that model is still under construction, but we have made enough progress with a model to where we felt we could use it for this forecast.

In 2011, we had some econometric models. In 2013, we have more econometric models, all the sectors covered except, as I mentioned, TCU in the case of gas.

In 2011, we incorporated climate change impacts for peak demand. In 2013, we're also adding in climate change impacts on the consumption side through changes in heating and cooling degree days for both electricity and natural gas.

As we go from forecast to forecast, we typically include new efficiency programs and standards that have become committed, that is, have been finalized and funded. So in this case we have 2013 and 2014 IOU programs that were not in the 2011 forecasts included, 2013 POU programs that were not included in the last forecasts, and new standards, 2013 Title 24 and 2011 Title 20 Battery Charger Standards are included.

A rough estimate, the new Standards create savings by the end of the forecast period statewide of almost 3,000 gigawatt hours, and then the IOU programs create savings by 2024 of around 2,000, a little bit less than 2,000 gigawatt hours.

As I mentioned, we do now do a climate change/climate zone analysis and in the 2011 forecast we had a predictive model for residential photovoltaics and solar hot water; for the 2013 forecast, we've added a predictive model for commercial CHP and PV.

And as usual, we do three scenarios, a high demand, a low demand, and a mid demand. A high demand, for example, is defined as higher economic and demographic growth, lower program savings, lower rates, and higher climate change impacts. In other words, we kind of rigged this so we get a nice spread on the three scenarios. There's always a consistency issue when you create scenarios like this. For example, in the High Demand Case you could say, well, if the economy is growing at a healthy rate, well, then customers probably have more disposable income and maybe are more likely to take part in an IOU incentive program; therefore, in the High Demand Case, you should have higher program savings. However, a scenario like that would be covered within the range that we've defined here between the high and the low.

Key inputs that we use, fairly intuitive, in this forecast versus our preliminary forecast back in May, employment personal income and manufacturing are all up a little bit, and that comes from more optimism from our econ/demo vendors regarding the housing market and the tech industry.

On the other hand, population compared to our preliminary forecast in May is down a little bit and I'll show you that in a minute. Commercial floor space is derived from the economic demographic data, for example, retail floor space is a function of personal income and projected retail employment and, of course, rates.

Okay, we have three scenarios for population and the 2011 projection is where we only had one scenario, it's shown in red there. For a high population we're using the Moody's projection; in the mid case we're using Global Insight, and in the low case we're using the California DOF projections. So what's happened since May is that Global Insight and Moody's have dropped their population forecast down, and I think it's to match more closely with the DOF. So we don't have much spread remaining between our population scenarios. You can see that the low and the mid are almost exactly the same now.

Okay, on to some results and, again, a reminder, this is a baseline forecast meaning it includes no adjustments for additional achievable energy efficiency. And also, this is using our old EV forecast; we'll be talking about developing a new one a little bit later on today. So compared to our 2011 forecasts there in red, you can see we're starting out at a lower point, and I'll talk about that in a minute, but after that lower point in 2013, our high demand scenario for consumption statewide grows at a faster rate than the 2011 mid forecast. The new mid forecast grows at about the same rate as the 2011 mid forecast. And the low demand forecast grows at a slightly lower rate.

Statewide peak demand, this is a non-coincident peak demand that is basically the sum of the individual Planning Area peaks. A similar story, we're at a lower point in 2013, but after that point the high demand scenario grows at a faster rate than the 2011 forecast, mid about the same, and the low demand at a lower rate.

You can see the little dot there for the 2012 weather normalized peak; when we're projecting peak into the future, aside from adjustments for climate change, we're using historically normal weather, so with the weather normalized peak there in 2012, as you can see, it likes right on the historical peak line, actual peak line. And that means in terms of the high temperatures that drive peak demand, 2012 was a relatively average year.

As I mentioned, especially in the case of consumption, we have flat growth from 2012 to 2013, and that happens because we're introducing new IOU programs in 2013, and new POU programs. Also, in the case of consumption, 2012, although it wasn't a very hot year in terms of the hottest temperatures, it was a fairly warm year on average, so compared to historical average, cooling degree days were higher in 2012 than the historical average.

So then when you go to 2013 and you're back, to historical average weather, there's a little bump down to consumption.

And there was relatively little growth between 2012 an 2013 in Gross State Product and Personal Income. That picks up again after 2013, especially at 2014 and 2015, but it's fairly flat in 2012 and 2013.

Our consumption per capita we're all proud of for California because it's relatively flat, and we project that trend to continue in our mid case, the dark blue there, until the end of the forecast period where it begins to increase a little bit with increased sales and usage of Electric Vehicles.

Now again, this does not include the additional achievable energy efficiency savings. If that were incorporated here, that would make a difference that you could see in this graph. For example, in the mid case, if we combined our mid demand scenario with our mid additional achievable energy efficiency scenario, which we'll show a little bit later on, electricity consumption per capita by 2024 would drop below that 7,000 gigawatt hours. So in other words, with AAEE savings incorporated, we would show a declining consumption per capita series in the new case.

End user natural gas consumption -- and that's typically flatter than electricity consumption, and one of the reasons for that is that Appliance and Building Standards have more of a relative impact on the natural gas side than the electricity side because there are much fewer end uses, therefore less end uses that need to be targeted to reduce consumption.

And compared to our 2011 forecast, we're flatter and we start out at a lower point. And the reason for that is, during the forecast period we have natural gas rates that increase between 2012 and 2024; a reduced need for heating because of climate change impacts, in other words, less heating degree days. And also on the natural gas side we're introducing Title 24 standards, and those standards also affect natural gas. So that was versus 2011. Our preliminary forecast -- here are the changes, adjustments we've made. We've updated our economic and demographic drivers, and I talked about that a little bit previously. We have lower rates for electricity than we had in the preliminary forecasts, and we'll show that in a minute. We've added impacts for Port electrification and High Speed Rail. Hopefully a new EV and natural gas forecast and additional electrification that we can add to the forecast that include that by the final version for adoption.

And for the first time, as I mentioned, in this revised forecast we're using a predictive model for commercial PV adoption. And at the behest of CPUC and ISO, we've included demand response impacts from critical peak pricing and peak time rebate programs; typically, we only include impacts from non-event based demand response. But the feeling is with these two programs, on the ISO side, on the supply side, they want to only include programs which they can count on; in other words, programs which give them direct control and can reduce megawatts. Whereas, these two programs, although they are event-based, depend on customers' price response or a response to financial incentives, which is not always certain. So the feeling was that it would be better to include this on the demand side instead of on the supply side.

So we have factors pushing us up relative to the preliminary forecast, and factors bringing us down, and the upshot is that we're a little bit higher than the preliminary forecast. This graph shows statewide electricity consumption for the mid case, the preliminary, and the revised. So, by 2024 we're around two percent higher than in the preliminary forecast.

For electricity peak demand, same story, our revised forecast is a little bit higher than the preliminary, around 1.2 percent higher. The reason the difference is smaller compared to consumption in comparing the revised versus the preliminary forecast is that we're adding in impacts like Port electrification and High Speed Rail that don't have much of an impact on peak, but do have an impact on consumption.

Okay, so here's a look at these new

factors we've included, these adjustments we've included for the revised forecasts. Critical peak pricing and peak time rebate programs in megawatts: by 2024, we're looking at about a 180 megawatt savings total among the three IOUs. So these numbers, first of all, for 2012, come from ex-post evaluated DR programs and, from 2013 on, the numbers come from the IOUs' program plans out to 2023. 2024 is just the 2023 repeated since we didn't have any projections for after 2023.

In addition to this, we also have around 37 megawatts reduction total from our non event-based DR by 2024. So on the demand side, in total, we have a little bit over 200 megawatts in reduction from demand response by the end of the forecast period.

High Speed Rail, this is from the first leg of the High Speed Rail system, Bakersfield to Merced, which is scheduled to begin operation in 2022. And these gigawatt hour estimates, estimated impacts, come from the High Speed Rail Authority's 2012 Business Plan and the associated Environmental Impact Report. And the Environmental Impact Report split up the effects, the impacts into the two service territories you see here, PG&E and Southern California Edison. So by 2024, there's a total gigawatt hour impact of around 220. The Environmental Impact Report also provides projected peak impacts, which amount to around 40 megawatts by the end of the forecast period.

We have Port Electrification. The At-Berth Regulations require that an increasing percentage of Port visitations and associated power used to maintain the ships' functions while they're in port, while they're berthed, be electrified; in other words, use electric rather than diesel power while they're in port. And that percentage increases from 50 percent in 2014 up to around 80 percent in 2020. So to develop numbers for port electrification, we made assumptions about the average load used by vessels that are in port, as well as berthing times, how long they're in the port. And to vary the scenarios, to develop a high, mid and a low scenario, we made different assumptions regarding the increase -- the growth in visitations over the forecast period.

So in the high case, we assumed the five percent increase, annual increase in port visitations; in the low case, we assumed no increase in visitations, and mid was in between the two. So by 2024, over all the ports affected by this regulation, so for LA of course that's the Port of Los Angeles, for PG&E that's Oakland and San Francisco, Edison is the Port of Long Beach, and San Diego is the Port of San Diego. Over all these different ports, by 2024 in the high case, we have about 320 gigawatt hour increase in electricity use, and in the low case we're at 210 gigawatt hours.

We always like to show the impact of our committed efficiency savings in the baseline forecast broken down into three categories: funded and approved utility programs, finalized and/or implemented standards, and price effects, meaning customer savings in the face of rate hikes by electricity use.

So this graph shows the consumption savings or gigawatt hour savings out to 2024, and this is relative to a benchmark of 1975. So this is saying basically, if since 1975 we had had no programs, no standards, and no increases in rates, in 2012 our consumption would be a little bit over 60,000 gigawatt hours higher. And the savings are highest in the low demand scenario, mainly because rates are higher, therefore you have more price effects. And I always like to give the caveat that this is making a strong assumption here, and that is basically nothing else would have changed significantly since 1975 if we hadn't had standards programs and rate hikes when we know in reality there would have been some natural changes that occurred in the market. So if some of this efficiency would have occurred anyway without any efficiency initiatives, this overstates the amount of savings, however, we could have gone the other way, we could have become less efficient, in which case this probably understates the total amount of savings.

Okay, we like to compare our forecasts to a peer econometric forecast done with the more aggregate econometric equations for each sector. And this first graph shows a total statewide consumption in the mid case for the econometric forecast and for the end use baseline forecast, with the econometric a little bit higher, and I would submit this is what you should expect because of the way the two different approaches handle efficiency. In the end use modeling, you're accounting for efficiency explicitly, whereas with an econometric model, you're capturing the trend of efficiency during the historical period and projecting that forward. So because I think we all would agree our efficiency efforts have intensified in recent years, if you look at a 30-year average for efficiency and you project that forward as the econometric model does, you're going to understate the total amount of efficiency in the future, and therefore overstate consumption.

Same story with peak: around two percent higher by the end of the forecast period in the econometric model for the mid case.

For natural gas, the difference is a little bit bigger, around six percent by 2024, again with the econometric results being higher. And I think this is also consistent with my theory about the way that efficiency is handled because, as a percentage of consumption, efficiency savings from standards are much higher for natural gas because more of the end uses have been captured by standards. Therefore, if you have an approach that doesn't quite capture all the efficiency impacts like the econometric model does, then that difference is going to be larger compared to electricity.

Okay, as a lead-in to our next presentation, a little bit about how we incorporate climate change in our forecast. We use scenarios developed for us by the Scripps Institute of Oceanography using 10 climate change models, so we have a total of around 20 scenarios. And for our High Demand Case, we pick a temperature scenario at the high end in terms of increases in temperature. For our mid case, our Mid Demand Case, we use a scenario that's right in the middle among the 20 or so scenarios in terms of temperature increase. And in our Low Demand Case, we don't include any climate change impacts. For electricity consumption, what we do is use these scenarios to project out changes in heating degree days and cooling degree days.

For natural gas consumption, we only need to worry about heating degree days because we're worried about heating. And for peak impacts, what we do is project out annual maximum daily average temperatures, and then using our models estimate the impact of that increase in temperature on peak demand.

So here's what climate change impacts look like for electricity consumption in the mid case. We have two opposing effects going on here: the top line shows you the increase in electricity consumption statewide from the increasing number of cooling degree days; however, that is offset somewhat by a decrease in the number of heating degree days as the climate gets warmer. So the net impact on electricity consumption is given by the dark blue line, which is a net of the effect of cooling degree days and heating degree days.

For natural gas, we only need to worry about the effect going one way from lower heating degree days, so in the mid case we have an increase in natural gas consumption a little bit over 200 million therms, and in the high case by 2024 around 600 million therms.

At peak impact from climate change, this shows the results for the five major Planning Areas, as well as the state as a whole. And by

2024, we're getting an almost 1,000 megawatt increase statewide from climate change and, in the High Demand Case, around 1,600 megawatts.

And I should mention one caveat here and that is that basically we're transferring a long term trend to the next 10 years and it could be in the next 10 years the effects are much lower as part of the long term trends, or the effects are much higher. So I just wanted to mention that these scenarios are not done specifically for the next 10 years. A long term trend for climate in temperature is developed by these scenario models, and we use that long term trend for the next 10 years.

Okay, before we get to Dan, I just wanted to mention a couple things. We'll probably make a couple of adjustments to our forecasts between now and the final version submitted for adoption. If we have a new Electric Vehicle forecast and natural gas vehicle forecast, as well as additional electrification, we'll incorporate that in the forecast. We discovered a problem with our QFER data for PG&E, so we have to change the starting point for the PG&E service territory for 2012.

In terms of what we're looking at after this forecast cycle, we want to start really working on new forecasting models that combine econometric and end use elements. The advantages of having end use elements is obvious, but we want to tie those end use elements to actual consumption using econometric equations. We want to move toward a level of granularity that best meets the needs of the users of our forecasts, so we'll begin talking about that after this forecast cycle.

I mentioned climate change; one of the other issues that we're concerned with for climate change is that warming may actually change the relationship between average temperatures and extreme temperatures, in addition to just increasing overall average temperatures. Well, this would change the relationship between what we call a one in 10 peak, a peak in a very warm year, and a one in two peak in a peak and an average year, and that has obvious planning implications. So that's what Dan is going to talk about, the impact of climate change on temperature distributions and on extreme temperatures versus average temperatures.

I also think it's time we start looking at the impact on load shapes of demand side policy, especially DG. I think we all expect that utility peaks are going to start shifting to later in the day because of the demand side policy, so we're going to incorporate that in our forecasts. I know a couple of the utilities have already done that in their forecasts. So these are things we're working on for our next forecast cycle.

And with that, I'll ask the Commissioners for comments or questions.

COMMISSIONER MCALLISTER: Yeah. Thanks, Chris. Good stuff and I guess on that last point I wanted to point out that, for our Standards work, you know, the Energy Commission develops the Time Dependent Valuation Metric and it's kind of an interesting interplay between the overall demand shape statewide and as that actually becomes more variable across the state, depending on how much DG and climate impacts, and all that, as we update the TDV for the 2016 round of Title 24, we're going to have to really dig in to, I think, your work to see if any changes are needed, or at least that after the mid afternoon hour may have a different weighting over time going forward, and we need to anticipate that as, say, the net peak moves later in the evening, or whatever happens with given demand side policies.

I also wanted to acknowledge the presence of some of our sister agencies. I see Simon from the PUC is here, so thanks for coming, I know it's a long trek for you to get over here and you've been here a lot lately; and then I don't see any familiar faces from the ARB, but I'm wondering if somebody from the Air Resources Board is actually here in the room. Great. Thank you for coming as well. I didn't have any specific questions, I'm pretty familiar with the process.

CHAIRMAN WEISENMILLER: A couple questions, or maybe more observations than questions. First, on your Committed Efficiency Savings slide, on 25, certainly one of the things that Commissioner McAllister and I are dealing with is a recent paper that deals with some of the structural changes, and I'm assuming here this is not dealing with changes in the industrial mix in California, or any of the other types of things that people have alleged, you know, or at least part of the energy savings that have occurred, you know, just sort of counter factual types of cases?

MR. KAVALEC: No, that's true; that is simply adding up the direct impacts from Standards programs and price effects.

CHAIRMAN WEISENMILLER: Yeah. Another question or observation probably sets a context for the climate change, is that the Governor last year had an event on extreme climate events, which really hit the notion that one of the things we're seeing now is basically the climate change on stairways, you know, that we'll always have hurricanes, we always have heat waves, but the magnitude, the amplitude of those events are much more significant than what we've seen historically, the volatility. So at least one of the things which I've always worried about is that, is our -- you know, we do an average planning one in two, and we do it one in 10, and so whether that one in 10 now is sort of shifting in a way relative to history, that we could have a much more extreme peak than we're contemplating, so that's one of the things I think we have to be on our guard for and, again, certainly encourage everyone to look at the website that went through the extreme climate event presentations from the Governor's Office.

MR. KAVALEC: Perfect lead-in for Dan Cayan.

CHAIRMAN WEISENMILLER: Okay. And I think that pretty much hits the major points. I think, again, great job on pushing this forward, certainly we're not done yet, and as you indicate in the last slide, this is something that's never quite done, but you always make progress. Thanks again.

MR. KAVALEC: Okay, so I'll introduce Dan Cayan from the Scripps Institute of Oceanography, a world recognized expert on climate change and climate change modeling. And he's going to talk to us today about the relationship between extreme and average temperatures and how that relationship may be affected by climate change. So, Dan, are you there?

MR. CAYAN: Yes, I am. Can you hear me?

MR. KAVALEC: Yes. We hear you very well.

MR. CAYAN: Very good. Thanks. I appreciate the opportunity to present here and good morning, Commissioners and audience.

So this is a progress report on a study that has been funded by the Energy Commission. We're looking at the potential for climate change impacts on the weather conditions that influence demand, and we're also looking at some shorter period factors which I'm going to show directly here.

Involved with this is a development of a so-called downscaling scheme in order to make use of the larger scale climate global simulations in the context of the textured environment, topography and so forth in California, we use techniques to translate these larger, very granular fields to the finer detail over the terrain. So we're working on that, and I'm not going to show results from that this morning, but we're making progress there. Instead, I'm going to focus on some early results in looking at some actual weather influences, and also some longer term climate simulation implications.

I'm assuming you can see my slides. I think that is going to be the keys to the card here.

MS. RAITT: Dan, can you hear me? Actually, this is Heather Raitt. It turns out we're having trouble seeing your slides, so Lynette is trying to get them up right now.

MR. CAYAN: Oh, okay. Well, I'll just give you cues, then. We're going from my titled slide now to the next slide, which is entitled "Load Forecasting."

CHAIRMAN WEISENMILLER: Okay, Dan, just hold on one second while we sync things up. Lynette, it seemed like you had it up on the screen, but that's this one, yeah, so if you could advance this one? Good.

MS. RAITT: We're getting there.

CHAIRMAN WEISENMILLER: Okay, we're ready now to roll.

MR. CAYAN: Okay. I just have to sync myself up now. So we should be on the second slide which is entitled "Load Forecasting?"

MS. RAITT: Yes, we're there.

CHAIRMAN WEISENMILLER: Yes, we're there.

MR. CAYAN: Okay. And in this case, if you focus on the plot that is at the upper left, which shows in the PG&E jurisdiction the change in daily peak load as a function of daily afternoon temperature, so-called Tmax, what we see there is we've arrayed several years of data here and -- by the way, my colleague David Pierce and also Mary Tyree have been really essential components of putting this presentation together, so it's a group effort. What we see here is that essentially in the summertime when maximum temperatures are relatively warm, we're on the steeper part of the demand versus temperature relationship, and in that case we actually can construct models that are functions of temperature to predict the daily load. And of course those models have errors, and we've been looking at how you might reduce those errors, and if we go to the next slide, number 3, what we notice is that one of the sources of errors seems to be that the presence or absence of stratus clouds along the coast, this is actually a composite that is drawn from positive and negative errs, that is, cases where the load was actually higher than predicted, positive errs, and less than predicted negative errs in the Southern California Edison territory, and it turns out that when we composite the cloud cover over those events, we see that a source of err is the presence of clouds in actually reducing the load, or the absence of clouds in increasing the load. So it's a factor that isn't accounted for in the present methodology for predicting daily load, but it might be and it might naturally be quite valuable in doing a bit better than what's done today.

So if we go to the next slide which is actually a climate simulation, this happens to be one of the newer climate models you probably all have heard the roll out of the Working Group 1 IPCC Climate Change Assessment, and this is one of the models that's involved there. This is an NCAR Earthsystem model with bio geochemistry and we're looking at a simulation that actually has been run from 1850 so that the models are run both retrospectively and prospectively, so this simulation goes back from 1850 through 2100, and roughly if you sort of follow the cloud of maximum temperature here drawn for a cell that lies over Sacramento, we see something like an eight degree Fahrenheit increase over the 21st Century. Just to give you an idea of how this compares to the observations in Sacramento, if we just click once here, we should see -- I'm not able to see what you're seeing -- but on my screen, I'm seeing a cloud of observations that overlies the period from the 1940's through the, well, near present period here. And you can see that the model essentially untouched, no bias adjustment and so forth, has done a pretty good job of replicating the envelope of variability in the Sacramento region. So this is the model that I'm choosing to show here for an example of what we're looking at as far as climate change impacts on temperature extremes that, of course, impact the load in the summertime in California.

So now I'm moving on to the next slide, which from this model shows the projected increase in two year return period daily maximum temperature, of course, these would be summer maximum temperatures, and 10 year return period, and Chris alluded to that, to those periods in his talk. And again, this is Sacramento, and this is from the climate simulation which, by the way, has been driven by the assumption of relatively high greenhouse gas emissions. This is the so-called RCP8.5 scenario. So this would be one of the higher of Chris's scenarios, or that would fall into the category of the high scenarios that Chris showed in this slides.

So on the left here, we see the two-year return Tmax, and these are laid out according to essentially a time series, a decadal time series, so 1963, '73, '83, and so forth, through 2033 here in this slide. So what you notice is the increase in two-year return period extreme maximum temperatures of approximately five degrees Fahrenheit over the modern period to the 2020's, 2030's. By the way, one important factor here is fact that these models include not only a low frequency multi-decadal trend which is driven by greenhouse gas accumulations in the atmosphere, but also they include essentially the whole suite of natural variations. So just as in observations, the models have variability from one year and one decade to the next.

On the right-hand side of this, I'm

showing the 10-year return maximum temperature values and showing how they increase over time and, of course, these are higher values because they're more extreme and, again, over the period of time from the '60s and '70s through the 2020's, according to the model simulation, we are seeing something on the order of a five degree increase in the extreme temperatures at essentially on the outer edge of the temperature distribution. Again, there's variation from one decade to the next and the other thing I guess to point out is the changes from the current period of 2013 in this model rendition, to the 2020's are very modest, at least for the 10-year return period. Now, this is only one model simulation and, of course, in order to do this justice, we need to look at several and probably different emission scenarios. So this is just an illustration.

Let's go to the next slide, which actually is a very similar picture, but now in this case I've carried this out to the middle part of the Century, this is 50 years essentially from present day, and you can see the increasing rise in both the two-year and the

10-year return values here. So we're seeing by mid-Century, this will become, I think, a very important factor that we'll have to contend with in projecting energy demand and so forth. In the nearer term, this is very incremental, but as time goes on, it climbs probably to levels that are quite substantial.

Going to the next slide, Chris had mentioned we're interested in the distribution of temperature extremes, so in this case for the 2003 period, I'm showing the temperature threshold that lies along the various return periods from one year to 30 years, from this model simulation, and you can see that the range from one year to 30 years is over 10 degrees Fahrenheit, so the extremes at the edges of the distribution actually get to be quite intense and, of course, we're interested to know if the shape of this distribution changes as climate change takes hold, and we've taken an initial stab at that with this particular model, again, just one simulation and one scenario. So if we click forward here, we see the distribution for the year 2023, and now you can see that the upper part of the distribution has jumped a fair bit across these decades.

Now, some of this change is probably what we might call sampling kinds of variability, that is, it's kind of the luck of the draw as to whether an intense extreme happens. So, again, the importance of looking at several models and so forth in order to get a fix on this, but I just wanted to give you an example.

And then finally, if we go one more click, you can see the shape of the distribution actually seems to retain its form that we saw in 2003, although it's been shifted up by several degrees as we get into the 50-year forward timeframe.

So following that, let's go to the next slide, this is actually observations from Sacramento, and this is my last slide, and I just wanted to show this to remind us of the really impressive amount of variation there is from one year to the next. In this case, what we're seeing is the highest daily maximum temperature for each year in Sacramento, going back to the 1930's, and it turns out that while there may be a subtle trend upwards in this record, it looks like the highest maximum temperature that has been observed at this particular station is actually in the early 1970's, and there's been lots of ups and downs and so forth. There's no reason in the future why we won't see similar year to year, and even decade to decade variation. And of course, that's going to challenge us in making the kinds of projections that Chris was talking about; he alluded to this phenomena in his remarks. It's as we get farther forward along the curves that I think we're going to run into really quite reliable climate change impacts.

The other thing I'd like to mention is amplifying a note that one of the Commissioners made in the interlude just before this talk, was the fact that there may be spatial variability that's imposed on electrical load demand phenomena, and one thing we've noticed from many of the climate simulations is the fact that warming appears to be more intense over the interior areas of California than the coastal areas as we go forward, so that's something that we'll have to look at, as well, in going forward.

So my final slide is simply a summary and what we've shown is that the marine layer cloud cover appears to be an important factor in implementing electrical load and it may help to reduce load forecast errs in making shorter period forecasts. We're looking into this phenomena of the temperature extremes at various return periods and there's more work to do there involving more models. What I showed in this talk did not actually include this downscaling methodology and that work is ongoing to produce an improve downscaling that's more appropriate for temperature extremes. And of course there's many diagnostics involving both the simulations and observations that need to be conducted.

So thank you very much and I'm glad to take questions if there's time.

COMMISSIONER MCALLISTER: Thanks for that, Dan. This is Andrew McAllister. Let's see, I guess I was just kind of curious, I've seen you talk in San Diego where I until pretty recently lived with my family and did quite a bit of work over there in climate discussions, participated in some sense, and really appreciate all of your work on that. I guess it seems like in some ways we have kind of what used to be maybe a clash of cultures that now are kind of learning to get along a little bit, you know, you have the kind of utility engineer culture and you have the academic climate science culture, which are both I think real. And I guess as we think about how to make your work as applicable as possible to electric system planning, and we're making some really -- this is great, I mean, I've really enjoyed your presentation and it's happening, clearly -- do you see any kind of challenges to focus your work on particular areas, you know, you mention here LA Basin, that get the kind of granularity, or get the kind of focus on where the people are, say, and where the actual electric infrastructure is, is going to be impacted, and translating this work over into how to prioritize electric system planning and investment. You know, do you have any observations on sort of that process and the learning curves on both sides of this discussion?

MR. CAYAN: We've been, I guess, having these -- it's kind of like a blind date where we have a sponsor, actually Guido Franco of the

Energy Commission, who most of you know, has been orchestrating this discussion, and clearly there's a lot of learning that has to go on, on both sides and we learn a lot from talking with the people in the industry and in the Commission, for example, in sort of designing this work so it is more applicable because we naturally don't know all of the thresholds and all of the issues that confront electrical power management and that side of things. So I think the continued conversation across the two communities, and certainly the culture that you mention, the cultural divide is real, but I think the discussions have been productive and I believe that this is something that can be exploited as we run into the future, especially in this environment where we're seeing really unprecedented change that's coming down the track. I think this is going to be essential.

COMMISSIONER MCALLISTER: Thanks and, you know, in a way we have kind of the biggest challenges in both worlds, I mean, we have lots of uncertainty, as you mentioned, near term variability and uncertainty sort of on the margins even though we know what's going on in general terms on the climate side. But we also -- you know, the public awareness of both climate and just electricity planning and sector issues in general are both abysmally low. And so here we are sort of taking both of them and we're combining them in a way that sort of multiplies that. And so I think the challenge on our front, well, really just broadly, is to communicate to the public, you know, a lot of the message can get lost in the near term noise and particularly in the immediate environment that we live in, that we really have to be disciplined to make sure that we're keeping our eyes on the prize. We can do that in California because our populace is really supportive of these issues and understands them to some extent, to a great extent, really. And our Governor obviously is very supportive of dealing with climate change, and so we're in a good situation in some ways, but, boy, the messaging challenge is really front and center on all fronts, I think.

MR. CAYAN: Yeah, I agree with that. I would say that -- trying to define positives in sort of bad situations -- I think that these extreme events offer opportunities for education and learning and I think we just have to be prepared with, you know, sort of a message that is getting some of these lessons across when these times arise, which they will in the future, and I think that we'll sort of ratchet ourselves forward. I think a good analog of this is the Sandy event in New York and how that's really been taken seriously into future planning concerning climate extremes and climate change. And I think that's one way to get beyond politics which, of course, really has been intertwined with these issues for many years, but it's hard to argue that these extreme events don't require planning and forward thinking.

CHAIRMAN WEISENMILLER: Yeah, this is Chair Weisenmiller. I want to take three things, the first one is in terms of the variability part, Not for this summer, but the prior summer I had the opportunity to brief the Governor on what we were doing in Southern California without San Onofre, and at least in that context it looked like we had like a 15 megawatt cushion in San Diego. So he asked me what was the temperature associated with that 15 megawatt cushion -- and this is on peak -- anyway, it got back to Chris and it was like a tenth of a degree, so again, that's on your peak side. So a lot of sensitivity, I guess. And moving on from that, you know, you had your plot of peak days, peak temperatures, and pointed out that early '70s really hot day, and the thing that we're really most concerned about is the heat storms, so it's not just that one really blast day as much as the third, or fourth, or fifth day --

MR. CAYAN: Right.

CHAIRMAN WEISENMILLER: -- and I don't know from your information here how much we can untangle that sort of heat storm phenomena; again, when we're trying to look at peak, it's not just that day, but it is that build-up that really we worry about.

MR. CAYAN: Yeah, that's a good point, Chairman Weisenmiller. Usually these extreme days don't happen in isolation and so there's often a persistent event. We saw that in the 2006 heat waves which, of course, are legendary. And in the models, of course, we can untangle that. For this presentation, we sort of simplify things and just looked at individual days, but we can cut this in a number of different ways and we can look at temperature excess over a number of hours and so forth. But one thing that we do notice over time is that not only does the intensity of each storm increase over the decades, but also the duration increases. And within any given day, the number of hours over a particular threshold -- 90 degrees or whatever the relevant threshold might be -- becomes longer. So I think we have to look at that sort of thing, as well, and the models now are equipped to at least take a stab at that. The models, of course, are not perfect, but they are an important device in looking forward.

CHAIRMAN WEISENMILLER: Yeah, certainly what I remember from the third assessment is that in the summertime, things were shifted up generally and, again, the peaks were worse. I guess the flip side of that question is, for Sacramento you've looked a lot at the hottest day, and part of our phenomena here that affects, again, our loads, in fact the whole operation of our systems, is we tend to have Delta breezes at night, so even though we might have a miserable day, that nights cool off. So one question going forward is do we expect those Delta breezes to be more or less?

MR. CAYAN: That's a great question and it's one that comes in many different forms to different communities. The Vintners in Napa Valley are also interested in that question. My instinct says that Delta breeze phenomena will be at least as strong as present day, if not a bit stronger, because of the temperature gradient that is setting up in these models where it looks like, as I mentioned, the interior warming is going to be greater than that along the coast. So it's essentially reinforcing the sea breeze phenomena that we have. But one thing that needs to be done there is we need better dynamical models that have essentially the full-on weather effects in order to explore that. And we haven't had many simulations in order to look at that with any confidence yet, but that's an item that is kind of on our plates and we're looking in order to understand that.

I will say this, that if you just look at the GCMs, they don't have evidence of that Physics going on, that is, the nighttime temperatures in the coastal domain and beyond the coast don't seem to warm any less than do the daytime temperatures. And, in fact, if you look globally at warming over the last several decades, it's actually the nighttime temperatures that have increased more than daytime temperatures. And furthermore, in looking at heat waves in California over the last few decades, what we've noticed is actually a bit alarming, is the fact that the nighttime periods in these strong heat waves such as 2006 are rather moist events, and nighttime temperatures did not cool as they have in previous heat waves, so we're actually seeing something in recent trends that runs counter to the Delta breeze phenomena. So we'll have to see how that plays out as we look forward into the models. But there's some evidence that during these events that Delta breeze phenomenon may be shut off.

CHAIRMAN WEISENMILLER: Yeah, that would be very important. I know SMUD has an adaptation plan in place and one of the things they have to deal with obviously is whether or not their distribution system can cool off at night, and has real implications for how they go forward.

I guess two other -- it would seem like if the Delta breezes are strong, we may actually have more wind at night, but the cloud cover may reduce the solar along the coastal areas from the rooftops, would be sort of another longer term phenomena, it's part of what I'm just struggling with in the Scoping Plan context with thinking more and more about what California looks like in 2030, where obviously the climate impacts are going to be much more pronounced than the time looking out where we're trying to do in the IEPR, and so particularly looking at what our systems look like in terms of loads and resources both, even more impacts there.

COMMISSIONER MCALLISTER: So much countervailing things, I mean, because if you have less solar, or if you have less sort of renewables being pumped into the distribution system, you might have less over-heating of the distribution grid itself, so you might need less cooling. It's really so many different tendencies here and picking them apart is very challenging. You know, I think we have no choice, we've got to move forward with doing this work and figuring it out. I guess, you know, if cloud cover in the Delta -- when you were talking about cloud cover being a factor, you know, I'm wondering if you have any understanding of how along a coast the cloud cover and the marine layer might actually change over time in LA or someplace where you have large populations?

MR. CAYAN: I wish. Again, that's a phenomena we're looking at. We recently completed a study looking at historical variation of cloud cover -- by the way, largely supported by the Energy Commission -- and find that cloud cover variation is not surprisingly a real important factor in mitigating high temperatures really along the length of the California Coast. We're looking at large scale factors that drive cloudiness and we're looking towards using those large scale factors as a guide in projecting how cloud cover may change in the future. I don't have an answer to that at this point in time, but preliminarily anyway it looks like the thermal inversions along the California coast, which are caused by the subsidence of air from a loft and, of course, they're a very large factor in both weather and air quality here, show signs of strengthening somewhat. Those inversions are also involved in the conditions that allow these stratus clouds to penetrate inland. And so my guess is that cloudiness is not going to decline in the future, I guess the question is whether it's going to increase, but that's going to take more study.

COMMISSIONER MCALLISTER: Great. Thanks very much. We're going to move on, but really appreciate your chiming in and a really good presentation. Thank you.

MS. RAITT: Thank you --

MR. CAYAN: I appreciate being able to do this from down here, saving the trip up. Thank you.

CHAIRMAN WEISENMILLER: Again, thank you.

MS. RAITT: Great, thanks. Our next speaker is Malachi Weng-Gutierrez. Thank you.

MR. WENG-GUTIERREZ: Good morning,

Commissioners. My name is Malachi Weng-Gutierrez. I work in the Demand Analysis Office. And I'm going to briefly review some of the revisions that were performed on the rates, the Electricity and Natural Gas Rates that feed into the Demand Models.

So we ended up using the same methodology. We used the E3 GHG Calculator as the basis of the developing Electricity Rate Scenarios. As with the preliminary, we looked at a number of the input assumptions that we could vary and we selected a few of those to kind of focus in on and look at how we might modify them in the context of comments we received in the preliminary forecast. So I'm only going to talk about those elements which I spent some time looking at, and which we modified for the revised forecast.

Trying to get to the punch line, the rates did decline significantly across many of the utilities. In general, it was about a 20 percent drop in rates across all of the different utilities for the different demand cases. And I'll go into the specific details as to why the declines occurred, but it was pretty significant. So for example, if you look at the Low Demand Case all the way to the right here, we were showing nearly a 20 cent per kilowatt hour average price in 2024, that is now an average of 18 cents per kilowatt hour, so a pretty significant drop.

So for the revised forecast, things that I focused in on were the 2013 rates, those were updated. Natural gas hub prices, the Natural Gas Unit and Office had a number of workshops on their forecasts and have had numerous iterations, so I was able to incorporate one of those iterations into the updated revised forecast. Also, since the preliminary, there were some auction events, the carbon auction prices that were updated to reflect recent events. And then one of the comments received was how we were applying the revenue requirements that were part of the auction to the general rates, and that was something that I spent some time on and looked at how we might apply them to the specific sectors which we forecast rates for.

And then obviously, as our demand forecast changes and alters, the amount of renewables also alters, and so we updated those to reflect a more recent estimate by our office.

And then finally, one of the things in the GHG Calculator which was dealt with in kind of a simplified manner was sort of non-generation components of revenue requirements, and so I spent some time looking at transmission and distribution costs and how those might be varying over the forecast period and tried to modify those to create a better representation of what I think will be those costs over the forecast period.

So the first thing that was updated, or that I referenced being updated was the 2013 electricity rates, and obviously for the preliminary forecast that work was done early on in the year and we didn't have all the information necessarily, or as the year progressed, obviously had more information as to what was happening, more filing, rate filings, more information coming out as to what the utilities were doing. And so I used a bunch of that information in addition to some conversations with the PUC to adjust the 2013 rates to reflect what was actually occurring as opposed to what was done in the preliminary, which was primarily to use the outputs of the model to generate the 2013 estimate. So because there was a significant increase from 2012 to 2013 due to primarily natural gas increases in the model, by doing this revision or this estimate of 2013 rates outside of the model, it brought down those 2013 rates pretty significantly.

And this is just the California-wide natural gas price that's used in the Natural Gas Model, the NAMGas Model they use. And you'll notice that the dashed lines there are what were used in the preliminary forecast. It's a very narrow band. And I think as part of one of their workshops, there were some comments to that effect, that it was a little too narrow, and so in the proceeding iterations of the forecast that they produced, they widened that pretty substantially. So you can see that the 2020 values are substantially wider than they had early on in the year, and so this is reflective in the rates that we have.

So in general, the high natural gas price here is going to lead to a higher price in our case, but it's offset by other changes, which then lower the rates significantly.

Again, I had mentioned that there were some adjustments to the carbon auction prices that we're using in the scenarios, this is just an update of those rates. You can see in the dashed lines again that's what was used in the preliminary, and then the solid lines are what are currently being used in the revised. So there was a slight decrease in those rates for most of the cases and then a substantial decrease in the mid case, again, reflecting I think some recent work and some other accounts. There was a Severin Borenstein paper on what the projected impacts would be to carbon prices, and in that paper he basically stated that it's going to be fairly flat over the forecast period to 2020, and then as you get closer to 2020, you might have an increase because of maybe constrained allowances and other things. But for the most part we envision that the rates will be fairly low over the forecast period. In our high case, obviously, we'll be looking at something that's on the order of magnitude of, I think, three times the floor level that we're estimating.

And then although the High Demand Case did not have a significant variation in the amount of renewables being incorporated into this estimate, the Low Demand Case did and that obviously changes the cost of generation significantly if the amount of renewables needed are lower than the amount of generation cost or if the revenue requirements associated with that are going to be substantially lower, as well.

So in allocating the revenue requirements for the carbon auctions under cap and trade, I looked at the three sectors that we forecast rates for, residential, commercial, and industrial. And I believe the way that it's structured now is that the residential sector will not really be impacted by carbon pricing in the auction, and that the revenues from the auction will actually be used to offset any costs that will be incorporated into the residential sector. So for our work, I basically removed all the influences of any carbon revenue requirements from the estimates and that lowered our residential rates a small amount.

The commercial sector, there are small commercial sector buildings which are also going to have allowance revenues allocated to them to offset any potential impact to their rates. It represents a small portion of the total commercial, but I've weighted the commercial revenue requirements by the amount of consumption associated with those small commercial entities. So that one also decreased slightly because of this, but it didn't really necessarily decrease it significantly, it was a small decline for the commercial sector rates.

For the industrial sector, their energy intensive trade exposed industries which are identified as being important to be sensitive to the impacts to those. Because they're such a small fraction of all industrial consumption, I ended up not trying to weight the industrial sector rates by that. I basically have not included any type of revenue being passed back to industrial sector activities, again, because I thought it was fairly small.

Then, as I mentioned, transmission and distribution, the way that the model had been -- there's a documentation for the GHG model which specified how non-generation revenue requirements would be handled, and then there was the model itself and they had some inconsistencies in how it was being implemented. And in general, it was using about a two percent growth rate over the forecast period. So I wanted to take a look and see whether or not that two percent was reasonable over all of our scenarios and what other factors might come into play in changing the transmission and distribution costs or revenue requirements. And so I looked at a couple of sources, one of the big ones obviously that I looked at was the LTPP for 2010, there was an Evaluation Metric Calculator, and in the Metric Calculator they have three scenarios that they look at, both distribution and transmission cost growth rates. And I looked to that to basically estimate some potential growth rates for the model. And this is basically what I came up with: the High Demand Case where you have a fairly low transmission cost growth, almost three percent, really is looking at a five-year period, and I think it's the last five years. So most of the transmission and distribution costs in the calculator and the LTPP for 2010 are sort of front loaded. So I used those low growth years as the basis of that estimate. Also, partly the reason behind it is that after 2020, transmission and distribution costs may decline significantly if there are no new requirements for expanding RPS. So arguably, the costs after 2020 may be lower than they have been over the next eight-year period, and so it seemed reasonably on the low end to go with something that was lower than the two percent that was the default case, default value in the GHG Calculator.

So all the way to the right, you'll notice that the weighted average annual case for the High Demand Case is lower than that which was the default input for the GHG Calculator, so we're having about a 1.5 percent growth rate. And in the Low Demand Case, or the high price case, it's about twice that, so it's about three percent.

This is just a summary sheet that I had this as a slide in the preliminary presentation, as well, and it showed all of the inputs and their associated values. So these are the updated values that we have for the revised forecast. The primary changes are the natural gas prices there are, again, a little wider. The renewable generation amounts there are reflective of what I just presented. And then the carbon prices are also modified slightly.

So in the end, this is sort of the set of the utility-based rates that comprise those averages that I showed in the first slides. These are all in 2012 dollars per kilowatt hour, so for the most part, even in the high cases, most of them are fairly low. There are obviously some cases where they're a little higher, so in the case of SDG&E, there's a higher rate there for their high case, but in general the rates are fairly low, they don't show that much growth over the forecast period. These are 2024 rates.

So I just wanted to quickly talk about the natural gas forecast, as well. As I mentioned, there were some comments about the natural gas forecast early on in the year, they worked on expanding the range of values that they used, so that actually played out in both the electricity rate forecasts that we have generated here, as well as our natural gas rates that we use in the models. And the changes primarily came about because of a closer look or refinement of the amount of coal fired generation that was being retired or converted to natural gas generation, and then they also developed a set of cost environments. So they looked at historic trends of costs associated with different components of natural gas and selected a set of conditions under which there would be high costs, and selected conditions that would also be low to create a larger or wider band of values that they used. And so that's what contributed to the widening of the forecasts that they had. And then obviously they took a closer look at infrastructure additions and exports to Mexico, and they did some work on the LNG sector, as well.

So this is the revised set of natural gas rates that we're using in the forecast. Again, if you were to compare this with what was in the preliminary, you'd see that the highs and lows are substantially wider, the mid cases are going to be a little bit higher than in the preliminary, but for the most part they're pretty comparable.

And then just in general, there are quite a few uncertainties associated with what rates will look like in the future, and I think they're pretty significant. So I wanted to highlight some of these uncertainties and just talk through a couple of them. This is my last slide.

So how San Bruno and SONGs, the revenue requirements, and the replacement costs, and what is allowed and disallowed in those proceedings will have, I think, a profound effect on rates in the future.

Obviously, in the model itself there are some cost assumptions about renewable generation; they don't necessarily have a time series of costs, there's a single cost that's attributed to that renewable generation. So arguably in the future, if costs of renewable generation decline, then that would have an impact on the retail rates in the future, and so I think how renewable generation costs progress over the forecast period would influence the rates pretty significantly.

The other on here -- distributed

generation is pretty significant, as well. I think how distributed generation is rolled out and what the potential impacts to distribution cost upgrades will be can be pretty significant. Obviously, those aren't incorporated into our rates, so that's something maybe we can look at in the future, or look at how we might want to create a scenario where we have maybe a high set of DG, and then look at how we might estimate those, how those revenue requirements would play out in the rates.

And then I just put here the Energy Resource Recovery Account. This is kind of part of -- there are GRC proceedings and then there's this Energy Resource Recovery Account proceedings, and in this proceeding they include things like natural gas prices, fuel costs, there's also I think the SONGs replacement cost, and things would fall under that proceeding. And so how all of those elements play out in the future, I think, and actually that there are in some cases delays to the ERRA proceedings and the decisions, so if those are put off, if the approval of the proceedings are not done in a quick fashion, or I guess what I'm trying to say is, if there are delays in the ERRA proceedings, then what you're doing is you're pushing the costs off potentially to future years, and so if we -- we haven't taken into account numerous kind of current ERRA account decisions because they have been delayed. So I think in 2014 or even later this year, there could be some proceeding decisions that would be made that could affect rates pretty significantly. And so I wanted to highlight that.

Obviously, I talked about transmission and distribution costs. That's in the context of renewable generation, I think those are fairly uncertain. Wholesale prices, obviously there could be market volatility that could lead to some additional uncertainties. And the coal fired generation and the natural gas exports, and even the natural gas plays, all kind of deal with natural gas demand. How those play out in the future, how many coal fired generation facilities are converted versus retired, I mean, all of that plays a role in adding to the uncertainty of these rates. But I think what we have right now is a fairly reasonable set of rates. And I would be open to any questions that the Commissioners might have on what was done to develop the revised set of electricity and natural gas rates.

CHAIRMAN WEISENMILLER: Thanks again. I think you've done a good job on stuff. I guess a couple -- at a high level -- first observation, I would say, is that I don't think anyone in this room expects disallowances for San Bruno and SONGs to be zero, so that would tend to suggest our numbers are high; I don't think anyone in the room would probably brave to come up with an estimate, although certainly when you do written comments, we would sort of welcome any suggestions there. But at the same time, as you said, that tends to bump things up. On the other hand, ERRA, I mean, like my impression was the Edison numbers are like a penny in the recent draft decision, so that sort of could count the other way.

Another observation is that, in terms of carbon auction, I think that the general expectation is with SONGs out the next auction will have higher numbers than we've seen before. But again, we'll find out when the auction occurs.

MR. WENG-GUTIERREZ: Yeah, and so for the auction rates, we've only incorporated those that actually occurred, the actual auctions. So we haven't really tried to project what future auctions will look like, other than to kind of develop our scenarios.

CHAIRMAN WEISENMILLER: Yeah. And you know, obviously the other thing which we never would want to dive into is you're looking at average rates and not rate structural effects, which again, looking at recent legislation, could have significant impacts going forward.

COMMISSIONER MCALLISTER: Yeah, just to reiterate that last point about behavior in the demand forecasts generally, not just the average rates, or not just your presentation, but also Chris's presentation and the forecast marginality that might be impacted by rate structures and how those motivate demand in the different sectors, so that's a very rich area for investigation going forward in the next year, next five years or so. But thanks for your presentation, Malachi, it was good.

I think we're going to slightly reorder the presentations going forward here so we can get in Chris Kavalec's presentation before lunch.

MS. RAITT: Right. Thanks. So next we'll hear from Chris Kavalec and then we'll hear Asish Gautam after lunch to talk about distributed generation. Thanks.

MR. KAVALEC: Okay. We reordered these two presentations because Floyd from Navigant is here and I understand he has to leave right after lunch, so in case there were technical questions related to the potential study, and additional achievable efficiency savings, we have Floyd here.

Okay, so as I said, an important step in going from our baseline to a managed forecast is the incorporation of additional achievable energy efficiency savings, AAEE. And we define these as likely to occur savings, or initiatives that have not yet been finalized, or funded, or approved, incremental to the committed efficiency savings that are already in the baseline forecast.

And these savings were developed using Navigant's Potential Goals and Targets Model, or PGT Model, which was used for the CPUC's

Potential and Goals Study over the last couple of years. These savings are specifically designed for the IOU or applied to the IOU service territories. We have five scenarios to proposed for you here, which I'll show in a minute, and the result of all this will be baseline forecast adjusted by AAEE as a step in developing a managed forecast for planning purposes.

So to do this analysis, our goal is to capture net market potential savings as opposed to economic potential, or technical potential that are not incorporated in our baseline forecast. And at this point in time, and based on what was modeled in the potential study, this includes post-2014 program measures because we already include the 2013-2014 IOU programs in the baseline forecast.

Future standards including Federal, Title 20 Applied Standards in the 2016-2018 time period, and Title 24 Updates in the '16, '19 and '22. And then there's also a tiny slice of efficiency savings that come from behavioral programs.

Okay, to examine AAEE savings, we need to develop scenarios and the PGT Model has a host of input assumptions that are used in defining a scenario.

The building stock, energy prices and avoided costs are based on the last adopted forecast, CED 2011. Incremental costs, meaning the costs versus the conventional or base technology, incentive level is the percentage of the incremental cost that's covered by the incentive. Unit energy savings are savings per unit per year. Total resource costs, those in the efficiency world are familiar with this measurement. The model requires that you define a threshold, and that threshold basically defines what the benefits have to be relative to the costs for the technology to be considered in the model. Measured density, which measures the penetration of a given technology or measure, the higher the penetration level of a given measure, the more familiar customers are with it and therefore, all else equal, the more likely there are to be additional adoptions.

Discount rates measure the value of costs today versus savings tomorrow. Word of mouth and marketing effects measure the willingness and awareness of customers under these technologies. And you have to make assumptions for the Standards, what type of standards are introduced and when, and what compliance rates you're going to assume for the different standards.

To come up with our five proposed scenarios, we started out with three initial scenarios developed in the potential study by Navigant and CPUC staff, a high, a mid and a low. We and CPUC staff then developed four additional scenarios as variations around the existing mid case from Navigant. The results and definitions of these scenarios were submitted to our Demand Analysis Working Group for comment. These comments were provided to our Joint Agency Steering Committee, or JASC, made up of management from the three agencies, CPUC, CEC, and ISO. And what came out of all that was five proposed scenarios for AAEE that look like this.

The three cases in the middle there, two, three and four, are all what we would call mid cases, Low Mid, Mid, and High Mid. The general consensus in the JASC discussions was that we wanted more than one version of a mid case as alternatives for planning, and that these mid cases should have the same assumptions regarding building stock and retail prices, so they should be consistent in that way. And it was felt that the alternatives to the mid case that we and CPUC staff developed, that I mentioned in the previous slide, didn't have enough variation around the original mid case, so they wanted alternatives that had more of a difference from the mid case.

The cases 1 and 5, those are cases that we, the Energy Commission, are using to pair with our high demand and low demand scenarios, respectively. So the way that we've paired this is we have our High Demand Case paired with the low savings, or Scenario 1, and the low demand paired with high savings, or Scenario 5. The building stock and prices in those two cases are consistent with the demand case to which they correspond, so in the low savings case, we have high building stock and low retail prices consistent with the High Demand Case, and vice versa for the Low Demand Case and high savings.

The way it turned out was that cases 1

and 2 and cases 4 and 5 are very close together, not surprising since their definitions are pretty similar. The key differences are that first, between Scenarios 1 and 2, is you have a little bit less emerging technologies. That 25 percent there, the first line for low savings that means that we allowed the PGT Model to predict adoption of emerging technologies given a certain threshold, and then we reduced that amount by 75 percent. And the reason we're doing this is because, as we know, there's a lot of uncertainties around emerging technologies. In the load savings case, we reduced the percentage that came out of the model. And really, the only other difference is the building stock and prices. In the Low savings case, it's consistent with our High Demand Case, as I mentioned, and the case to Low Mid, it's consistent with the Mid Demand Case.

Cases 4 and 5 again are very similar. The difference there is, again, the assumptions for building stock and prices, consistent with the Low Demand Case in Savings Scenario 5, and consistent with the Mid Demand Case in Scenario 4. One other difference is that we allowed --

we assumed compliance enhancements would occur in Scenario 5, meaning the rate of compliance for these different standards would increase over the forecast period to a maximum of 100 percent.

One other source of overlap to account for is lighting savings assumptions that we make based on the Huffman legislation. In our end use models, we modify the lighting we see as meeting unit energy consumption from lighting, and we modify the UECs in our end use models to be consistent with the Huffman requirements. In other words, by 2017, we've reduced the lighting you receive by 50 percent in the residential sector, and by 25 percent in the commercial sector.

This is just a step we took a few years ago to improve what we thought the accuracy of the forecast, given the Huffman legislation has teeth and people expect that these lighting savings are going to occur. However, they're not associated with any specific program or standard. And during the forecast period, you would expect that these lighting savings would overlap with lighting savings in the potential study. So by 2024, said overlap reaches a little bit over 3,000 gigawatt hours and 450 megawatts.

And in the results that I show you from this point on for AAEE, this is the potential study results using the efficiency initiatives that I defined earlier with this overlap subtracted out.

So here are the five scenarios for the combined IOU service territories in gigawatt hours and, as I mentioned, the cases 1 and 2 and 4 and 5 are very close together, as it turned out. And by 2024, in the Mid case, the blue line there, we have 21,000 gigawatt hours of savings in addition to the committed savings that are already in our forecast.

In the High cases, they were looking around 35,000 and in the Low Mid cases 12,000 to 13,000 gigawatt hours. A similar pattern for the megawatts. In the Mid case, we reach around 5,000 megawatts of additional savings for the combined IOUs. And for natural gas, around in the Mid case a little bit over 400 million therms by the end of the forecast period. And you will notice on the left-hand side of this graph, we start out in the forecast period with negative natural gas savings, and that happens because the potential model -- the PGT model models interactive effects. So the beginning of the forecast period, you're getting some savings from new lighting and other appliance technologies that increase slightly requirements for heating, and therefore natural gas usage increases by a small amount at the beginning of the forecast period. And then after that, the savings begin to go up when we new program measures from 2015 on.

Some interesting factoids: as I indicated earlier, the emerging technologies were a source of a lot of discussion in the DAWG and in the JASC meetings. We ended up with quite a range for our emerging technology penetration in these scenarios, from less than 300 gigawatt hours in Scenario 1 by the end of the forecast period to almost 10,000 gigawatt hours in Scenario 4, the High Mid savings case in 2024.

Standards savings make up a little bit more than a third of the gigawatt hours total in 2024, little for gigawatt hours, and the percentage is a little bit higher for megawatts, almost 50 percent. And the reason the megawatt percentage is higher is because we have Title 24 Standards that have a lot of impact on peak. And natural gas, because of the interactive effects, among other things, natural gas standards percentage is much less than electricity.

And one of the key findings reflected in these numbers is that the commercial sector has the most potential in electricity in terms of future efficiency savings, although it remains the residential in the case of natural gas because residential is a much larger user of natural gas than commercial.

This table shows the total savings by IOU for each of the scenarios. The amounts, the magnitudes are mainly a function of the size of the IOU, the amount of sales by the IOU, although I think San Diego's totals are a little bit proportionately less because they don't have as much in relative terms, potential on the industrial side.

Okay, now if we take our mid baseline case and some over the three electricity IOU service territories, and then make adjustments for each of the AAEE Mid cases, this is what we get. The top line shows the baseline total for IOU sales summed over the three IOUs. The red line below that shows what happens if you incorporate Low Mid AAEE savings, or Scenario 2. The green line below that is after incorporating Mid AAEE savings, or Scenario 3. And the black line at the bottom shows the forecast if you incorporate the High Mid savings. And basically what you get is, in the Low Mid savings case is slightly increasing forecast for combined IOU sales, and almost a flat forecast if you apply the Mid case, and a declining forecast if you apply the High Mid case.

Same basic picture for the megawatts. And for natural gas where the forecast is fairly flat to begin with, so what you end up with when applying the three mid-savings scenarios to the IOU baseline Mid Scenario for natural gas, is three declining forecasts. The erratic pattern that you see there at the beginning of the forecast period comes from the swings in natural gas prices at the beginning of the forecast period.

Now, combining our Demand Scenarios with the Savings Scenarios, as I mentioned, we're combining our high demand baseline with low savings, or Scenario 1, and our low demand baseline with high savings, or Scenario 5, to sort of preserve a healthy range in our forecasts.

As always, as I mentioned before, there's a consistency issue involved here. These scenarios are consistent in terms of the pairings of savings with baselines. They're consistent in terms of building stock prices and program savings, but as I said earlier, you can certainly make the case that in a high demand scenario with relatively high economic growth, there should be more program savings. But in a minute, I'll show you what happens if you reverse the pairing, if you pair the high demand with high savings, and vice versa, what you end up with.

Okay, so this graph shows forecasts for the IOUs adjusted for AAEE savings, as I just described in a previous slide. The words "Baseline and" shouldn't be in there, it should just say "Combined IOU Adjusted Sales Forecast." So again, we get in the High Demand Case, we get a slightly increasing forecast. The Mid demand paired with the Mid savings scenario for the IOUs, you get a relatively flat forecast and then a declining forecast in the Low Demand Case.

Now if we reverse that order, you can see what happens to the range there. We basically end up at the same point by the end of the forecast period. This is pairing high demand with high savings, or Scenario 5, and low demand with low savings.

A similar pattern for megawatts using the scenarios pairings as described. For natural gas, again, we start out with a relatively flat forecast, so when we apply these in all three demand scenarios, so when we apply the AAEE savings, the result is three declining forecasts for natural gas.

So I'll just close with some uncertainties related to this analysis that we should always keep in mind. At the end of the day, what we're really interested in is estimating the cumulative net impact of all these savings on our consumption or peak demand. And that depends on the amount of decay, the amount of time before measures burn out and are replaced.

So both we and Navigant make assumptions for the way that measures burn out. We apply using expected useful life for the measures. But in reality, we don't really know a lot about decay in the real world, so this is something where we need a lot more data through surveys and other analyses to really get a better handle on how much decay actually goes on from year to year.

This analysis does not include two notable efficiency initiatives, Proposition 39 and AB 758, although Navigant has made some initial estimates of the impacts of Proposition 39, but they're not included in these savings. AB 758 is not explicitly accounted for, although the potential study does incorporate whole building measures that would be consistent with AB 758.

As I said before, there are always uncertainties related to emerging technologies. Our estimates for Standards are very preliminary at this point, especially when you're talking about 2019 and 2022 updates to Title 24. And as always, there's a great need for updated data. The baseline on which these savings are based in the potential study come from the 2004 commercial survey and the 2009 residential survey, badly in need of update for the next potential study.

So with that, questions, comments?

COMMISSIONER MCALLISTER: Yeah, thanks very much, Chris. So I wanted to take advantage of the fact that Floyd is here and ask a question about sort of what levers -- well, I guess we had the discussion about sort of how could we model some of these initiatives like 758, less so Prop. 39, but you know, it being more recent, but how could we reflect those initiatives in some way in the forecast. And I wanted a little bit more explanation from Floyd about sort of what sorts of levers do you have to pull that sort of can map over onto initiatives like those. You know, you can't sort of put a box in there that says "check the Prop. 39 box" and see that you get, right? You've got to sort of assemble the kinds of measures that you think are going to happen under that initiative. Maybe you could talk a little bit about that process and what levers you do and don't have in the model to be able to mimic an initiative like Prop. 39 or 758. That would be great so people online can hear.

MR. KNEIPE: This on? Okay, great. I think that, you know, we look at the model now and it kind of divided the world into two camps, or two types of efficiency; one is stock turnover where you're changing out equipment for a more efficient piece of equipment, and I think that this model did a very good job of accounting for that, and that's primarily what Chris is showing.

The other part of the efficiency world, though, is changes in operation of energy management and how people use that equipment once it's installed. And I think that there is some significant room to improve those estimates in this model. So operational changes account for about 10 percent of the potential that we built into the model, and I think that that's likely understated. And when I look at things like Prop. 39, it's conceivable that that could be used to improve, you know, the management capacity at K through 12s and the community colleges, to actually use their equipment more efficiently. And there was a study that was done and it was one that I did looking at institutional programs, and I suspect that there's upwards of 30 percent additional yield in terms of additional efficiency that can be achieved through just better management practices. And I suspect that's where Prop. 39 and AB 73 -- or SB 73, I guess -- are going to have an impact, and that's what we've kind of taken a preliminary look at, but it's one of those things that's going to need additional research.

So I think because operational savings are underrepresented in this model, I've always considered that the Mid case is a fairly conservative look going forward.

COMMISSIONER MCALLISTER: Thanks. So that makes sense. I guess to the extent that Prop. 39 and 758, though, are going to stimulate turnover, you know, actual installation of equipment, for example, turn over existing stock than they are represented in the model, right, and then we're talking about penetration rates and uptake and things like that, that you do actually have leverage for in a model. Is that right?

MR. KNEIPE: We do. And AB 758 is represented, as Chris said, in the model as a whole building initiative. And we did have some additional yield from commercial whole building activities, but it was fairly muted for residential, and that we just haven't been able to identify what are the market dynamics that are causing people to participate. It's probably not, you know, financial self interest as -- the whole building retrofits that we saw in reviewing program records didn't necessarily pencil from either a cost-effectiveness standpoint for a utility, or make sense from a payback standpoint for the customer perspective.

COMMISSIONER MCALLISTER: Interesting.

MR. KNEIPE: So if we can identify why people are doing that and if there's a way to increase that uptake, we can certainly have a more robust impact from whole building activity on the residential side.

Other aspects that I understand are potential under AB 758 such as, you know, mandatory upgrades at time of sale, we didn't consider those, but we have the infrastructure to do that.

COMMISSIONER MCALLISTER: In terms of like disclosure, if we were to push a disclosure program and said, okay, at sale, or you know, even voluntary or mandatory, but assuming some coverage, some significant coverage in the marketplace of disclosure, for example, whether in a public building at all, public buildings or commercial, residential, whatever it is, you could express that, the impact of that in terms of equipment already; like if we were to just sort of make a logic model and said, okay, if we do this disclosure, then we anticipate penetration of X measure would go from 10 percent to 40 percent, something like that, that is expressible in the model today, right?

MR. KNEIPE: It is. That's built in.

COMMISSIONER MCALLISTER: Okay, so I guess, you know, I would just make the observation that I think this is a rich field for research and certainly in 758 where we're looking at how to make -- how to get better data, make it more available to more folks, and sort of get the community more broadly, whether energy efficiency, environment, local government, whatever it is, kind of engage in figuring out those market dynamics that you referred to, and then hopefully bringing that back into the tools that we have at our disposal to actually do the forecasts and the efficiency forecasts in the future, I just think that the time is completely ripe for doing that. And that we sort of -- if we limit ourselves in terms of what we can express in the model, then we sort of -- you know, the tail ends up kind of wagging the dog in terms of what we think is going to happen in the marketplace, it sort of limits our options and maybe our creativity, even, our program design.

So I think -- well, so I just want to kind of get that on the table and say, you know, in a way it's a challenge to Chris's team, you know, it's make your models more detailed, but really it's a challenge to all of us to kind of get on the -- put our thinking caps on and sort of figure out how we can better understand the marketplace because, as you said, people are doing things that don't seem purely economically rational -- I think that's wonderful, I think that people -- we want everybody to retrofit their homes and go out there and buy the LEDs whether or not -- for whatever reason they have, you know, and certainly with cost-effectiveness being a strong driver, but not for everybody, and it's not the whole equation for almost anybody, I would say. So I really am excited about the opportunity, the possibilities here going forward, and I think in fact we have to make this happen much more broadly if we're going to meet the aggressive goals that we have, you know, in 2030, 2035, 2050.

So, anyway, I know we will be having a lot of conversations along these lines, certainly with 758, you know, your input with you launching a model to kind of come up with a bottom up estimate of what the potential is for different initiatives within 758, matching that up with the goals and sort of seeing what the gap is, the market transformation, or the market acceleration kind of activities, or what's going to fill that gap. And so I think really we need to look at this from all perspectives and figure out where we can do better. So thanks for all your work on this.

MR. KNEIPE: Thank you. I should mention that in 2014 we'll be updating the model to account for the MMV findings from the '10-'12 programs, and there's a lot of data in there on financing and on whole building activity, and on a range of emerging technologies that are going to, I think, change the Mid case probably by the end of 2014.

CHAIRMAN WEISENMILLER: So I have some questions, too, while you're there. One is, when you look at existing buildings, and I would note the Scoping Plan which is coming out today as a pretty high priority on existing buildings, do you have statistics on rented gross space in residential and commercial, what the split is?

MR. KNEIPE: We do have that data, though we didn't look at it from a split incentive standpoint exactly --

CHAIRMAN WEISENMILLER: Yeah, because my presumption is that that's a very very tough market to hit, is rented space, both in residential and commercial. And I keep hoping in multi-family, I keep hoping this part of 758 we find a silver bullet, although again I'd be concerned somewhat if we were ignoring that, the split incentives in these studies.

MR. KNEIPE: You're concerned that we may be overstating it because we're not discounting the rental -- the mixed market for that?

CHAIRMAN WEISENMILLER: Yeah.

MR. KNEIPE: Yeah, that's a valid concern.

COMMISSIONER MCALLISTER: Well, and also, you know, if we determine that, say, in multifamily rented space, certainly the lower income sort of certain communities in the state that really it's not going to happen unless it gets paid for by somebody else, and so if we think achieving the policy goals requires us to scale up direct install programs, and we can parse that out by income, geography, whatever, but if we do the calculation and we say, okay, we've got a direct install on X number of millions of units, that's going to be a fair amount of money it's going to require --

CHAIRMAN WEISENMILLER: Yeah, I mean, again, I think looking at the low income, the EJ, you know, there's a bunch of reasons why even if it costs a lot of money, I'm saying we just do it --

COMMISSIONER MCALLISTER: Oh, absolutely.

CHAIRMAN WEISENMILLER: -- but I want to make sure that we have a pretty good idea of what we may have to do there. So again, it would be good to understand how much going forward, where we need to have special programs to deal with the special needs of rental space and that's going to be very important.

The other sort of challenge from my perspective, do either of you have a sense of how much uncertainty is introduced by the antiquated load surveys? Or do we want to describe the fact that we're sort of running more and more on older and older data?

MR. KNEIPE: Well, I think it varies by sector. The residential sort of baseline data we have from those most recent saturation surveys is 2009, so it's not that bad because the market doesn't change that quick. We've been able to account for changes by looking at program records and set time. The commercial market, which is much more complex, as you know, is much older, and I think that there's significant uncertainty in that. I think the most uncertain sector is probably the industrial sector where there hasn't been a solid look at, say, just standard motor efficiencies in that sector for 15 years, I believe. So that sector, in particular, is lacking from any sort of primary research that is anything less than 10 years old.

CHAIRMAN WEISENMILLER: I know, that's very hard. I do notice that the commercial is where a lot of this potential savings are, so, again, I think certainly we believe that's a very high priority on getting that survey updated.

COMMISSIONER MCALLISTER: Yeah, we're putting in definitely a recommendation in the IEPR to update the CEUS and that needs resources, but just to be clear, I think if we think that the direct installs are necessary, we've got to go out there and make the case, and we've got to call a spade a spade and go out there and shake the resources out so we can -- if we're going to take our goals seriously, we've got to get that done.

CHAIRMAN WEISENMILLER: Yeah. Again, to the extent we're trying to make the policy case for direct install, is the more we can have that very explicit and not just swept under the rug, is it's going to happen the better.

I guess the other question I'm trying to understand is that there's a sort of progression; when we do research, we come up with new technologies, they move out through the utility incentive programs into the field, and then eventually they're moved into our standards. And so the question is, as we go forward longer and longer, I mean, God, you're talking 2022 Standards, how are we dealing with potential double-counting?

MR. KNEIPE: Well, that's a difficult question. I think what happens is we use -- it depends sort of on the timing of when the stock is turning over what's the existing baseline and what's the new code, so you may have a current code turning over in five or 10 years that's going to be subject to some speculative code or aspirational code that we're uncertain about. But I mean, we're accounting for that. Projecting code past what's currently on the books, or a forecast in the next update, is --

CHAIRMAN WEISENMILLER: No, it's hard, I mean, I know we've struggled back and forth, we have a target for Zero Net Energy, and so once we hit that for residential, do we do anymore codes, you know, you can certainly talk about optimizing, but again, the further out you go, you know, we have enough trouble trying to fit what's going to be in the 2016, you know, anyway, and how much of that is somehow embedded in some of the other programs.

MR. KNEIPE: We are plagued by how to treat the interplay between distributed generation and energy efficiency, such as the residential market. How do you value energy efficiency in a home, or a home that has significant DG installation?

CHAIRMAN WEISENMILLER: Yeah. No, and certainly we're struggling with debates on how much we push energy efficiency in the new construction, or what's the interplay between energy efficiency and DG in those facilities, those structures.

COMMISSIONER MCALLISTER: I think I'll have plenty of opportunities to talk to Floyd going forward, so I don't need to ask all my questions right now. And so we've hit the Chair, so that's good. Thanks a lot. I guess, thanks, Chris, for lots of good meaty stuff for the next round of updates, and certainly in 758, and to some expect Prop. 39. We're going to be leaning on your resources, as well, so that's good.

MR. KAVALEC: And thanks a lot to Floyd and Navigant for helping us put these numbers together.

MR. KNEIPE: Thank you.

COMMISSIONER MCALLISTER: So we're going to go to public comment.

MS. RAITT: Right. So we'll go to public comment for folks who need to leave before the end of the day.

COMMISSIONER MCALLISTER: Do we have anyone on the web that has raised their hand at all? Just to sort of get a throughput check here. Okay, so we only have one blue card right now which -- oh, I think Sierra also wants to make a comment, but I'll call Simon Baker from the PUC. Go ahead.

MR. BAKER: Noon, Commissioner McAllister, Chair Weisenmiller. Really pleased to be here today and thanks to all of you and your staffs for the hard work to prepare these forecasts. I know it's a great amount of effort.

My name is Simon Baker. I'm the Manager of Demand Side Programs for the PUC's Energy Division, and I'm here representing the Energy Division today.

Our team has been collaborating really closely through the Demand Analysis Working Group and the Joint Agency Steering Committee to develop these additional achievable energy efficiency scenarios that have been presented here today. And together with the ISO, we've been working with the Energy Commission to improve coordination related to the energy efficiency in the Demand Forecast and its use in procurement and transmission planning. This is a part of our overall efforts to implement joint commitments made in response to Senators Padilla and Fuller's January 30th hearing on energy efficiency.

And today we'd like to register a request, and that request is that the CEC adopt in the context of the IEPR proceeding a single forecast that includes all reasonably expected to occur additional achievable energy efficiency to be used for procurement and transmission planning purposes; and using the new lexicon that was introduced here today, we're essentially requesting that the CEC adopt an adjusted forecast for procurement and transmission planning purposes.

I also want to thank the Energy Commission staff for working with us to include certain demand response effects that had not historically been included in the forecast as committed effects, specifically we're talking about the critical peak pricing program and the peak time rebate program. And we're pleased that the staff were willing to work with us on that. So thank you very much for this opportunity to be here today.

COMMISSIONER MCALLISTER: Thanks very much, Simon. So any part of that you can put in written comments and submit, that would be great. And let's see, on the demand response, the latter part of your comment, I totally agree and actually feel like, you know, demand response is one of these things whose time has come and we need to characterize it more carefully so that we can understand, again, the market dynamics and sort of carry that forward and get it into the forecast in ways that reflect its long term potential, you know, as understand it. So it's certainly another thing for next year to implement the next step or two further.

I guess I'll defer to the Chair on process, but I certainly want to acknowledge that the agencies are working together incredibly tightly on a number of different fronts and that's really critical that we continue to do that. There's a lot of great comments and reasons why we should be doing that all around and also obviously sort of some current reasons why we need to do that with SONGs and other issues. Most notably is Southern California kind of efforts that are going forward. So I think certainly the agencies need to come together and indicate what forecast or what scenario is going to drive them, but I don't necessarily think that the IEPR itself, adoption, is the place for that, but I'll defer to the Chair on that point.

CHAIRMAN WEISENMILLER: Yeah, well again, certainly want to thank people for their technical assistance. Certainly going forward, we'll struggle with these issues and make a decision. So thanks and certainly looking forward to next year doing better.

MR. BAKER: Okay, thank you.

COMMISSIONER MCALLISTER: So, Sierra, go ahead.

MS. MARTINEZ: Is this on? Hi, my name is Sierra Martinez. I'm the Legal Director at California Energy Projects at NRDC. I want to first of all thank the staff and the Commission today for all the work that's gone into this forecast; I know it's a tremendous amount of effort.

Two comments today, one on process and one on content. The first on process: NRDC appreciates all the work that the joint energy agencies are conducting to try and come up with a joint forecast, however, today we have not seen the results of a single agreed upon joint forecast that includes all future energy efficiency.

At the January hearing that Simon Baker mentioned, the joint agencies committed to coming up with a single forecast to include all that future efficiency. Today, we saw a baseline forecast presented, an adjusted forecast presented, as well as discussions of a managed forecast. We would strongly recommend that all the energy agencies come together to decide upon a single forecast.

My concern here is that, by the time the joint agencies do come to agreement, there will be limited time for meaningful stakeholder feedback on that particular forecast. There were five scenarios presented today, previously there were informal comments on seven scenarios, but a single forecast is essential for meaningful stakeholder contribution.

On the content of energy efficiency, NRDC recommends that the Mid case, additional achievable energy efficiency, gets adopted in the IEPR process. As we heard from Navigant today, this is a conservative estimate of future energy efficiency. Within a potential study process, emerging technologies were de-rated due to a risk adjustment factor, only a subset of all emerging technologies were studied. These emerging technologies include far off in the horizon technologies such as LED technology. It is overall a conservative approach to what future efficiency includes.

A second point on the content is that, on POU energy efficiency, it's critical that this Commission include the work that the POUs have done to forecast their efficiency over the next 10 years. The Energy Commission does great work with the POUs to develop this process, and the POUs have worked hard. It's essential to include those additional 10 years of energy efficiency. Thank you for considering our comments.

COMMISSIONER MCALLISTER: Thanks, Sierra.

CHAIRMAN WEISENMILLER: Yeah, thanks.

COMMISSIONER MCALLISTER: I'm assuming you'll file written comments, as well, on these points, yeah, they'll be useful. Thanks.

MS. RAITT: And that's it. I this we can break for lunch, coming back at 1:45?

CHAIRMAN WEISENMILLER: Yes. We'll be back in an hour.

(Break at 12:45 p.m.)

(Reconvene at 1:51 p.m.)

CHAIRMAN WEISENMILLER: Commissioner McAllister has pulled away, so hopefully he'll be back before the end of the day, but let's start.

MS. RAITT: Great. Our first speaker is Asish Gautam.

MR. GAUTAM: Good afternoon, everyone. My name is Asish Gautam and I'll be going over the Customer-side Distributed Generation Impacts for this revised forecast.

First, I want to go over the different sources of data we use to track DG activity in the state. The first is our CEC 1304 Power Plant Data. Here, we're capturing data from large cogen plants and Industrial/Mining sectors.

The next source is the Emerging Renewables Program. This program is being managed by the CEC, but it's phased out now, but there was quite a bit of PV installations under this program, so we're still tracking that.

The next program is the SGIP Program here, it used to fund PV for the non-residential sectors, and also cogen, so we're still tracking that. And this program has undergone a lot of changes and it used to be that for a couple years the cogen was not really funded, but now cogen is back into play.

The next source is the California Solar Initiative here, this is a the big PV program that funds retrofit for residential and retrofit on new construction in the nonresidential.

The next source is the New Solar Homes Partnership managed by the CEC. We also get a lot of PV data from POUs that report annually to us, so we also take that into account.

The new program that we just started tracking a few years back was the Solar Thermal Program for the PUC, this is for the solar hot water installations.

We also rely a lot on the CSI, and that's should be in the PV reports, basically the program database gives us installation by county and we use the evaluation reports to translate capacity into energy and peak impacts. Other sources include PV cost projections from EIA. We also have taken some analysis on CHP, which was done by ICF about a year or two ago.

Some of the updates for the revised forecasts, we've updated our Program Data. We have revised electric and gas prices, revised housing stock and floor space. We also took comments from the preliminary forecasts to limit residential PV adoption to owner occupied dwellings, and we used our RAS server data to estimate how many homes were owner occupied versus rentals.

One thing for this revised forecast is using a predictive model for the commercial site to PV instead of a trend analysis like we did in the preliminary forecast.

The structure for the residential and commercial sector PV and solar hot water is based on payback periods, so we use payback as an input into a logistic diffusion model to estimate market penetration and apply that to housing stock, or commercial floor space to estimate new adoption. Results for the forecast differs by demand scenario because it differs in fuel prices, housing stock. We use a CSI dataset and EIA's forecast for estimating PV prices, solar hot water cost comes from a PUC study. We use our residential sector models to estimate PV sizing and use that to estimate what's used onsite versus exported to the grid. And exports are valid at the net surplus compensation that was published a few years back.

For the commercial sector, we look at meeting onsite demand for power and for CHP do thermal end uses as hot water and space heating to facilitate the analysis for the commercial sector relying on CEUS server data. Here we have profiles from 2,900 sites representing 12 building types and about four usage sites categories.

We take our CEUS profiles and benchmark it to our QFER sales data and also calibrate it through our commercial sector end use model efforts, and also grow these profiles to make an adjustment for the floor space growth. One of the tools we receive from the CEUS surveys is our DrCEUS energy modeling tool, and this is used to create the load shapes to facilitate the CHP thermal assessment.

One of the neat things that we did differently in the commercial that is different from the residential is that we tried to use natural retail electric and gas tariffs because of the need to account for energy and demand charges separately.

CHP technology details come from the SGIP incentive program data, and also an earlier study that was done by ICF for the CEC. For the commercial model, we also rely -- we use the same data for residential sector model where we use the CSI data and the EIA projections for PV cost.

Next, we use the DrCEUS generator load shapes. These have impacts such as generation on onsite use, export, and grid purchase.

We account for any existing CSI in SGIP incentives and tax credits for installing PV and CHP, and at least in the commercial model the payback assessment and adoption modeling happens the same as in the residential model.

I'm going to go over the statewide results, the results for the individual Planning Area will be given in the Planning Area results presentation later this afternoon.

First is the non-PV Energy Impact. Our starting point for 2012 was 12,500 gigawatts of generation onsite use, growing to between 14,400 and 14,500 gigawatt hours by 2024, implying a growth rate of about 1.2 to 1.3 percent. The scenario results are very close to one another because of offsetting effects. In the high demand scenario, we have low electricity prices and low gas prices for the cogen, but the floor space is higher, so we have more buildings, but in the Low Demand Case we have high electric rates and high cogen, natural gas price for the cogen unit, but the floor space is lower, so they kind of tend to balance each other out, so the scenario is sort of much more closer together.

Next is the non-PV peak impact. Our estimate for 2012 was just under 1,900 megawatts and we estimated that by 2024 we would get just under 2,100 megawatts and 2,144 megawatts, implying a 1.1 to 1.2 growth rate. Most of the growth happens in the commercial sector.

Next is the PV energy impact. Here, all three scenarios are above the 2011 forecast. The 2012 impact was estimated at 2,200 gigawatt hours and we estimated that, by 2024, the impact would be about 7,200 to just under 10,000 gigawatt hours, implying a growth rate of 10.5 to 13.5 percent. Here, unlike the CHP, the bill savings effect dominates, so there's more separation between the scenarios.

Next, we have the PV Peak Impact. Our

2012 impact was just under 700 megawatts and growing to between 2,026 megawatts, again, pretty high growth rate of between nine and 11.5 percent. For the PV, we estimated that by 2024, there's still capacity to be about 4,400 megawatts in the high demand, to about 5,700 megawatts in the low energy demand scenario, and we see that all three scenarios will meet the CSI 3,000 megawatt goal by 2017.

Some of the key uncertainties in the forecast. I think just within the last two weeks with the passage of AB 327 and the just released E3 study on the net engineering, these are some key uncertainties because they can really change project economics and that would have an influence on future adoption. There's also some retaking of retail electric design, which would have an impact depending on how residential tariffs are redesigned, or there's flattening of the tiers, or in the commercial sector a shift from, say, energy only to energy and demand charges. There's also the impact of the Federal Tax Credit dropping from 30 percent to 10 percent.

For CHP, some of the uncertainties are

around the interconnection procedures and standby and departing load charges, so these are still around.

As far as our next steps, we still have our ongoing data updates and one of the things that we're happy to see is that the PUC is considering collecting the CSI data from the utility interconnection procedure, so we rely a lot on that database and it's good to see that, at least the PUC is looking into continuing collecting this data.

One of the things we would like to do is revise our residential sector model to incorporate the retail electric rates. We were hoping to do that in time for the revised forecast, but we were unable to because of the time constraints.

One of the other things we would like to do is to focus on CHP in the Industrial/Mining category sectors. That's it for me, so I'll take any questions.

CHAIRMAN WEISENMILLER: Do you have any sense of the uncertainty associated with the -- in terms of translating it back into megawatts or gigawatt hours, the net energy metering redesign, or the rate redesign?

MR. GAUTAM: In terms of how it would influence project economics?

CHAIRMAN WEISENMILLER: Yeah.

MR. GAUTAM: We were able to account for that in the commercial sector because we are using actual retail rates and we have load shapes to estimate the monthly carryover.

CHAIRMAN WEISENMILLER: Right.

MR. GAUTAM: But one of the things from our CEUS data is it was noticed that the net benefits are not as significant, and so we want to look at why that is the case. We think it's mainly to do with how the CEUS was conducted and the type of sites that may have participated in there.

CHAIRMAN WEISENMILLER: Uh-huh.

MR. GAUTAM: As far as the residential sector, one of the things that we have talked with -- E3 was hired by PUC to do the CSI evaluation, so they have a lot of production profiles that we would like to incorporate and account for the net metering impacts. But right now our residential model is on an annual basis, so we can't really account for any kind of changes to the net metering.

CHAIRMAN WEISENMILLER: Right. Okay, thank you.

MS. RAITT: Okay, thanks. Our next speaker is going to be Tim Olson to discuss the Electric Vehicle Forecast.

MR. OLSON: Okay, thank you, Mr. Chairman and staff and attendees at this meeting. I'm going to go through quickly what we're projecting in our Electric Vehicle -- Preliminary Electric Vehicle Demand Forecast, and I'm going to walk through some comparisons to the ZEV Mandate and ZEV Executive Order. And what we're not covering today is anything on natural gas vehicles or any of the other alternatives. A lot of that was covered in previous workshops. I'm going to touch on a some baseline information, information that was presented previously, just for a little bit of context to refresh our memory.

So this information presented today has been conducted in a kind of broader framework with other demand -- transportation demand analysis. And because we're focusing on Electric Vehicles, we're going to kind of focus our discussion around Electric Vehicles are primarily a light-duty, light truck type of technology, we're going to focus on the forecast efforts, the process we went through on the forecast related to light-duty vehicles, or passenger vehicles and light trucks.

And that process was a consumer choice survey, 3,500 households responded and several hundred commercial businesses, to address things on kind of how their behavior -- what their expected kind of key things that would convince them to buy a vehicle, or to change out a vehicle. And we took that information which was a snapshot in time for 2013, and we also kind of took another -- added another analytical element to that, and that's what we call the Vehicle Attributes Analysis. So in this case, we have information and hired consultants, Sierra Research and the group of consultants who basically tried to explain what the changes in vehicle technology are going to be over time. In our case, we were looking at the 2050 horizon, the further you get to 2050, the less accurate that projection may be in terms of technology change and other attributes that we're expecting to kind of measure in this process.

And this slide here kind of indicates the key factors that go into that vehicle attribute, that last bullet. Passenger vehicle dominated by fuel cost purchase, the vehicle price. And these other items listed here are also factors and they were considered in this kind of how do we project changes over time.

I want to also highlight the part of the vehicle survey, these kind of attributes over time, because we need to factor in the incentive needed to offset the differential cost. But right now -- I'll show you some more information later that shows vehicle fuel cost, in this case electricity on a cost per mile basis, cheaper than for internal combustion engine counterpart. But the vehicle costs are more expensive today; we think that's going to change over time.

We add in previous testimony, information from David Greene, Oak Ridge National Labs, National Research Council, National Academy of Sciences, present information showing that the cost of these vehicles, particularly electric and hydrogen, look like they're going to drop over time and, in fact, the first time I've heard this and after 2030 Electric Vehicles and hydrogen fuel cell vehicles will be cheaper than their counterpart ICE engine vehicles. After 2030, based on analysis, kind of projected analysis, from light weighting of material and components of all vehicles, but much more a greater light weighting in the electric and hydrogen. So that's a factor that we need more information on, and you'll see why I'm referring to this as preliminary, we need to go through some other steps.

So just a little bit of context. We're projecting that, overall, passenger vehicle light trucks will grow from where we are today, around 27 million, in a range of 41 to 49 million in 2050. A key factor there is population growth. We're still in this growth mode of net new people in California, I think it's around 350,000 new people per year, net new people, and that will taper off over time from what demographers are saying. And then also Gross State Product growth, these are key factors in the likelihood of additional passenger vehicles coming on to the marketplace.

I'm just going to touch on this, see if you can read that. Baseline stock in 2012, as you can see, these are the different categories we look at and you can see that, for a couple of these, particularly for mid-size and compact, they dominate the total. But you can see kind of a spattering of things throughout the different vehicle classes.

This information was presented in a previous workshop, and I just want to refresh your memory about some of the other information we have.

This slide here also kind of indicates the technology introduction timeframes showing gasoline, electric, and you can see from this one here, I don't know if you can read that, but multiple models noted here that PHEVs and EVs show expansion in the next few years and there's -- maybe you can project from this there are certain timeframes for vehicles to get into the marketplace in a mass market way. Just to give you some background.

Other factor for the background here is projected gasoline prices. This is based on U.S. DOE and AEO in 2013 crude oil and refining petroleum product forecast. We modified it for California wholesale retain margins and what we're showing here is both nominal and inflation adjusted prices. These are on a dollars per gallon basis, they reflect crude oil price as the high, is in 2014 $120 a barrel, rising to $286 a barrel, this is in inflation-adjusted prices. Reference case here, $985 a barrel in the 2014, $197 in 2050, and then the low case is a decrease, $83 a barrel in 2014, dropping to $74 in 2050. This is a factor also in how Electric Vehicles are going to perform in terms of market growth, not as significant as the cost of the vehicle, but it's a factor of operational cost and I'll show you another slide here basically showing that it's a factor for Electric Vehicles because they are 3.4 times more efficient than gasoline ICE engine vehicles and operating costs will become one of those things to consider.

So Electric Vehicle Growth -- at least for the near term, between now and 2025, stimulated by some government policy, government intervention, a very key factor and I've kind of identified the two California efforts and one at the Federal level.

The ZEV Mandate -- we'll have a speaker after me, Anna Wong, who may make more comments about the ZEV Mandate, but in essence you've got two things here that show a growth rate. The ZEV Mandate requires OEMs to offer vehicles for sale in California by 2020 and 2025. We've projected some growth rates with those agreements or expected agreements to meet those goals.

CAFE Standard Vehicle fuel economy, you know, we're at a point where we're very soon to be at 35.5 miles per gallon. That law also requires automakers to meet a fleet average of 54.5 in 2025. And we're not sure that this was completely factored in on our analysis, and this is one area we're going to go back and look at. Some of the information we were borrowing for this kind of projection nationwide was the National Academy of Science, and I'm not sure that they've really covered that 54.5 mpg by 2025, completely. But why is that a factor? Well, Electric Vehicles are 3.4 times more efficient, it's a way of contributing to that CAFE Standard, and we think that there will be growth from CAFE in Electric Vehicles.

The Governor's Executive Order calls for the State of California to make the infrastructure ready for a million vehicles in 2020 and 1.5 million in 2025, reflecting expected full implementation of the ZEV mandate, and maybe a little more expansion from that.

What I don't have on here is the other government support in the form of grants and rebates, grants for infrastructure in the early years, and rebates for Electric Vehicles that Energy Commission and ARB jointly implement. So that's another factor in the kind of what's on the record.

This slide reflects the ARB's future vision to achieve greenhouse gas emission reductions of 80 percent below 1990 levels in 2050, and actually there were several scenarios developed for this, this is one that indicates maybe the optimum way to meet that greenhouse gas goal in 2050 is a mix of several zero emission vehicle options. And so you can't ignore this kind of directive from the AB 32 and our expectation that transportation contributes 38 percent of its fair share, percent of the emissions and greenhouse gas emissions are from transportation, so we're expecting that to be the contributor for the transportation sector, and we think that the way to do that in the long term is really the Zero Emission Vehicles, of which Electric Vehicles are a significant part of it.

This information listed here also, this graph also, reflects some work done by David Greene of Oak Ridge National Lab, I mentioned earlier, in conjunction with the National Academy of Science and National Research Council, where they were basically saying that to reach that 2050 goal outlined here, some changes would -- some technology changes would occur and that's primarily a light weighting of the vehicle and components that are more extensive than with internal combustion engine vehicles.

And the ZEV expectation, I'm going to kind of defer to the ARB staff on this coming up after the meeting. In essence, it's showing that in 2025, over 15 percent of the new vehicles sold in that year will be the ZEVs, a mixture of things, and as some of you may know, with the Zero Emission Vehicle Mandate, it's kind of a flexible thing where automakers can have a different mix of fuel cell vehicles, plug-in electric, and battery electric to meet that goal. And so I'm going to let ARB staff kind of elaborate on this.

Now, some of our initial projections on this case, compact vehicle prices, show a downward trend. This is something that we would like to revisit in our discussions with our contractor, and also with ARB staff because, just within the last week, a new survey of automakers has been completed and we're not reflecting that in this analysis. We think that a key topic in that survey was the cost of the vehicle, and we may have some new information we'd like to factor in. But also, I'm not sure -- what I'd really like to do is compare this to David Greene's study showing the pretty significant drop in vehicle price by 2030 for the Fuel Cell Vehicles and Electric Vehicles, and probably revisit this kind of conclusion here.

One of the factors I mentioned earlier was the fuel price as a reflecting operating cost for electric, in this case Electric Vehicles. And we've got this displayed two ways, retail basis comparing all these options in a common unit, gasoline gallons equivalent. You can see that, in this case, electricity is fairly high on this, it's the highest source here. But when you factor in the efficiency of the vehicle on the right-hand side, cost per mile basis, electricity is the cheapest option compared to these other -- and this is for the reference case, it's very similar in other cases, the high and low -- actually, not so much on low, it's also similar on the high. So we're looking at this factor as a contributor to Electric Vehicle market penetration, too.

Some of our initial results on forecast show that these are projected sales at each year, that the results here were very close to the ZEV Mandate projection at the high petroleum price scenario, not so much on the reference case here, and this is another factor we'd like to revisit primarily because of information we didn't reflect in these automaker surveys that were just completed. But this is still in the ballpark of the ZEV Mandate projection.

And this is a cumulative total for on-road Electric Vehicles and you can see it's also -- the high case here, high scenario which would be high petroleum cost, to achieve the -- I think we end up achieving the 1.5 million one year later than the Governor's Executive Order, so 2026 is the date that that occurs in the high case, much later in the medium and the low case.

So just to kind of sum up here, we are -- these are our preliminary findings: we want to revisit the vehicle costs, but we think that getting more information, more data from automakers, would be very helpful in this process and we're expecting planning a consulting meeting with ARB staff and probably one-on-one interviews with automakers this fall.

So that's my presentation; any questions, Mr. Chairman or anybody in the audience?

CHAIRMAN WEISENMILLER: Yeah. I guess, Tim, just to make sure we're clear on the record. So going from here, what do you see as the major steps and the timing?

MR. OLSON: From here, the major steps are some additional consultations with ARB staff within the next couple weeks, followed by some interviews that may take about six to 10 weeks with not every automaker, but as many as we can do. And then we will reflect that in some additional analysis with our consultant. We'll include our consultants in those meetings and, of course, this means we're going to be getting some confidential information, which we then have to aggregate, and that's going to take some time just to put that together. So I'd say probably within 10 weeks we will have another version of this.

CHAIRMAN WEISENMILLER: Okay, and in terms of the major information you're trying to pin down --

MR. OLSON: Mostly vehicle cost and the change of vehicle cost over time.

CHAIRMAN WEISENMILLER: Okay, and at this stage how different is your forecast from what we adopted last year?

MR. OLSON: From where we are now, I think we're slightly under the ZEV Mandate case. We had a high case that was almost four times what everybody else was saying in 2011, so we think that needs to be revisited.

CHAIRMAN WEISENMILLER: Obviously, part

of your challenge is splitting between fuel cells and battery electric.

MR. OLSON: Right, and that -- the preliminary discussions with ARB staff indicate that there are going to be some changes with hydrogen vehicles from those surveys, and we need to know more about that in terms of numbers on the road.

CHAIRMAN WEISENMILLER: Okay, and I guess I'm just trying to understand relative to last time whether you see fuel cells higher or lower in terms of the split?

MR. OLSON: Well --

CHAIRMAN WEISENMILLER: Realizing it's all preliminary at this stage.

MR. OLSON: -- it looks like it may be very close to what was proposed before, or forecasted before, just a slower growth at the front end on hydrogen, but it will pick up later. And remember, let me go back to this one slide, the real growth occurs after 2030, so we want to make sure these programs and these regulations are working in the early years to get to the point between 2025-2030, when we see the significant market launch and mass numbers, particularly for the passenger vehicle.

CHAIRMAN WEISENMILLER: You know, as you know, a lot of people are trying to compare the hybrids, you know, where they were in their trajectory versus where the battery electric is at comparable times.

MR. OLSON: Right, yeah. So the Prius business model is one that we look at, but there are some others that are similar that could be like a 10-year timeframe to get into the significant mass production. And one other factor I didn't put on here is turnover rates; we've been looking at like 7.7 years, some are saying maybe with the recession gone, that might change, it might be a shorter timeframe on turnover, and so those are things that we need to revisit, too.

CHAIRMAN WEISENMILLER: Okay. But at this point, you have the Academy study, you have the ARB, and you have your analysis and somehow we're trying to take the best of all worlds.

MR. OLSON: We like to take the best of all worlds and show that those studies and the kind of transparency of those projections side-by-side in some cases.

CHAIRMAN WEISENMILLER: Okay.

MR. OLSON: Any other questions?

MR. COLE: If you back up the slides when you talked about the adoption --

MS. RAITT: Could you state your name and affiliation for the record?

MR. COLE: Oh, yeah, Sasha Cole, CPUC, Energy Division.

MS. RAITT: Thank you.

MR. OLSON: Which slide?

MR. COLE: What you had is an earlier slide where you tell the adoption you got 40 to 50 million -- keep going back -- okay. I'm wondering why those lines are so linear. It seems like you're either going to get a very very low amount, in other words, the whole system will crash out, or there will be some kind of nonlinearity when you start to get charging stations and all the externality -- I mean, we see all these technology systems and they just don't get adopted in this linear way like this over time.

MR. OLSON: Well, remember, this is total vehicles, all vehicles --

CHAIRMAN WEISENMILLER: Yeah, this is

total vehicles, so that doesn't follow that logistical curve.

MR. COLE: Okay, great.

CHAIRMAN WEISENMILLER: But you should -- we're running behind, so I would encourage you to follow-up with Tim afterwards and let's go on to the ARB.

MR. OLSON: Okay, Anna Wong from the ARB will join us and has comments.

MS. WONG: Okay. Well, I think Tim covered it pretty much. And I can answer any questions, but just to explain the regulation compliance scenario a little bit more, it is just a compliance scenario. Manufacturers have a wide range of flexibility in meeting the requirement, so we took our best guess as to what we thought the vehicle mix would be, and everybody took most of the flexibilities allowed in meeting the requirement, and ran a scenario. And that's how we came up with that 50.4 percent, but it's highly dependent dependant on the number of vehicles sold in California every year, and we base that on our MFAC numbers for new vehicle sales, and that gets revised every time we revise MFAC, so we are sure that they will be complying, and so we came up with a scenario in which they all comply in a way that makes sense to us from what we've seen them comply in the past.

So that would be my only note on the compliance scenario, and I'm happy to take any questions that you might have about anything related to the regulation.

CHAIRMAN WEISENMILLER: Yeah, well again, I think the major thing that would help us is, to the extent the Air Board has forecasts, you know, however you want to caveat those, if we could have those in our record so that we can sort of compare and contrast them --

MS. WONG: Yeah.

CHAIRMAN WEISENMILLER: -- with what the staff is doing at this stage that will help.

MS. WONG: Yeah. So again, what we have adopted we have not changed, and so our compliance scenario, we don't have better data now that they're going to comply in a different way.

CHAIRMAN WEISENMILLER: Okay --

MS. WONG: So that's -- but you know, we definitely could look more into the assumptions with your staff and try to figure out of there is maybe a way that makes more sense, but none of our regulation numbers or requirements have changed since we've adopted them in 2012. So it hasn't -- we don't have a better forecast at this point, and so we agree with the numbers that they're using.

CHAIRMAN WEISENMILLER: Okay, and certainly any insight you can give the staff on sort of this -- obviously we try for a low, base and high, so trying to figure out what the low and high are would be good.

MS. WONG: Well, we would always like to say that the regulation is the low case because any over-compliance, as we've seen over many years, manufacturers tend to over-comply because they're always padding their future, they're always making sure that they have enough to comply in future years in case there's something that goes wrong; most of these companies are very conservative.

So we would say that the regulation sets a lower bound and anything above it is expected, but we don't know how much above it, it sort of depends on how the market takes up the technology.

CHAIRMAN WEISENMILLER: Okay. Thank you. Yeah, as I said, I think the theory was we were supposed to be where we are now at 1:45, it's now 2:30, so I need to move folks along, but certainly encourage you and Tim and everyone to talk, but just to try to bring us a little bit closer on schedule.

MS. RAITT: The next speaker is Nick Fugate. Thanks.

MR. FUGATE: Good afternoon. My name is Nick Fugate and I'm going to present the IOU Planning Area forecast results. And I think the way these presentations are set, I'm going to cover the Planning Area results first, followed by climate zone results if that's applicable to that IOU, and then finish up with sort of what we saw in Chris's presentation, the service territory forecast adjusted with the additional achievable energy efficiency scenarios.

So I'm going to start here with the SDG&E Planning Area forecast, and after my presentation, after each presentation I'll invite the utility representatives to come up and provide comments, as well.

Okay, we have our Baseline Consumption Forecast for the SDG&E Planning Area. These scenarios are higher than what we presented in May, about 300 gigawatt hours in the Mid case. And the case grows faster than the preliminary forecast by about a tenth a percent, and that's due in part to the drop in revised rate projections, so the result is that the Mid scenario growth rate is 1.52 percent annually, reaching about 25,000 gigawatt hours by 2024.

Embedded in this forecast, we have Electric Vehicles impacts which are increasing consumption by roughly 1,200 gigawatt hours by the end of the forecast period, and this revised forecast features 12-19 gigawatt hours of consumption due to anticipated Port electrification which, as Chris mentioned, is new to this forecast. Climate change also accounts for an additional 190 to 300 gigawatt hours in the Mid and High cases, respectively.

So peak demand growth is about 1.4 percent annually to reach just over 5,400 megawatt hours in the Mid case. Self-generation is expected to contribute about 400 megawatts of peak reduction in the Mid case, 250 megawatts of that is due to PV systems. Electric Vehicles contribute little to peak, only about 29 megawatts in the Low case and 73 in the High.

The combined impact from event-based pricing programs and non-event-based demand response programs reaches about 50 megawatts and that, again, as Chris mentioned earlier, is a new feature in this forecast, the price demand response programs; and climate change impacts at 72-131 megawatts in the Mid and High scenarios.

Okay, so SDG&E only has the one climate zone and so I'm moving straight into the adjustments for the additional achievable energy efficiency. And so this first slide shows our Mid baseline scenario adjusted with the three different levels of mid additional EE, the Low Mid, the Mid, and the High Mid. So the reference of the Mid baseline here grows at about 1.2 percent a year over the forecast period, and then when we add in the additional achievable efficiency, which ranges from 1,389 gigawatt hours to 3,442 gigawatt hours, this brings an annual growth rate down in these other scenarios to .7 percent, .4 percent, and then this low one here is actually negative at -.1

percent.

Okay, so here again we're looking at service territory sales, but in this case rather than adjusting the Mid by the three Mid scenarios, we're adjusting each of our Low, Mid and High baseline scenarios by -- or the Low, Mid and High demand scenarios will be adjusted by the High, Mid and Low additional achievable efficiency.

So this Mid case, we actually saw that on a previous slide, and that's the Mid paired with the Mid, which grows at .4 percent annually, and then the higher case here grows at 1.4 percent, which is actually higher than our unadjusted Mid baseline forecast, and the lower case declines at a rate of -.9 percent.

Here's our adjusted service territory peak. Again, this is the Mid scenario adjusted by the three Mid efficiency scenarios. The unadjusted Baseline growth here for reference is 1.36 percent annual growth and, after the adjustments, the growth rates are .75 percent, .43 percent, and -.16 in the lowest case.

And here again our low paired with the high EE and high demand paired with the low EE.

The high case here is growing at 1.4 percent and the low case is -1.0 percent. And that's actually all the slides I have for San Diego. So I'll defer to the Chair if you have any comments before we invite San Diego up.

CHAIRMAN WEISENMILLER: Let's invite San Diego up.

MR. VONDER: Tim Vonder, SDG&E. We will probably file written comments. We have a lot to review yet, there's a lot of detail and staff has done quite a bit of work in revising their forecast, so I'd like to commend staff and their effort. You can see the presentations so far today by Chris and company that quite a lot has been looked into in revising the forecast, and Chris has turned over quite a few little rocks and made a lot of improvements. And so we think he's done a very good job in doing that.

Bottom line-wise, we're pretty much in agreement with their revisions. We are looking forward to seeing a change in Electric Vehicles, I think everyone is looking forward to that, so if it's quite possible to include another revision before the December adoption date, that would help a lot. Other than that, I'd like to congratulate them on a job we believe is well done and hopefully we can prepare some constructive written comments. Thank you.

CHAIRMAN WEISENMILLER: Okay, thank you. The one question I have is, do you have an EV forecast for San Diego that you could also submit in the record?

MR. VONDER: We don't have a new one yet.

CHAIRMAN WEISENMILLER: Okay.

MR. VONDER: We're working toward there also.

CHAIRMAN WEISENMILLER: Okay. Will you be before or after Tim?

MR. VONDER: I don't know. We'll see.

CHAIRMAN WEISENMILLER: Thank you.

MR. FUGATE: Thanks, Tim. Okay, moving on to Southern California Edison. Here are our Baseline Consumption Forecasts for the SCE Planning Area. These scenarios are, again, higher than what we presented in May by about 1,100 gigawatt hours in the Mid case. This amounts to almost a tenth of a percent increase in the growth rate over the preliminary and again goes back to lower rates, but part of it is also due to the new adder such as Port electrification, which represents 60 to 92 gigawatt hours in the Edison territory, and also the addition of high speed rail considerations, which are expected to contribute another 61 gigawatt hours by the end of the forecast period.

So all that combined gives us a Mid baseline scenario that grows at 1.05 percent annually to reach 113,802 gigawatt hours by 2024. Embedded in the consumption forecast are impacts from electric vehicles which are expected to increase consumption by nearly 2,000 gigawatt hours. And also, climate change accounts for another 365 to 497 gigawatt hours in the Mid and High cases.

So for peak demand, peak demand grows at a rate of 1.4 percent annually, reaching 25,450 megawatts in the Mid case. Self-generation is expected to contribute 1,500 megawatts of peak reduction in the Mid case and about 700 of that is due to PV. Electric Vehicles, again, don't contribute very much relative to consumption, about 48 megawatts in the Low case and 118 in the High. And combined impacts from event-based pricing programs and non-event-based programs reach almost 50 megawatts. And climate change impacts at 355 and 570 megawatts to the Mid and High scenarios.

So for the Edison territory, we do forecast by climate zone. And here's a map of our climate zones colored by Planning Area; Edison's is the yellow section and it's made up of climate zones 7 and 10, those are the inland zones, that's the Southern San Joaquin Valley plus Riverside and San Bernardino Counties, and then Climate Zones 8 and 9, which include Long Beach, Orange County, Ventura County, and the Inland LA Basin.

So the fastest growth in both consumption and peak demand over the forecast period is projected to be Inland, that's due to the expectation that migration will continue from coastal to inland areas. Growth in population from 2013 to 2024 in the Mid case is projected to be 28 and 19 percent, respectively, for Climate Zones 7 and 10. And that's compared to just five and nine percent for Climate Zones 8 and 9.

Inland climate zones also see higher peak growth due in part to climate change considerations, particularly potential climate change impacts contribute to faster peak demand growth in Climate Zone 7 in the Mid demand scenario. In the Mid demand scenario, increases in annual maximum temperature are highest in this zone, in Zone 7.

Okay, so on to impacts from additional achievable energy efficiency. And here we're starting with the service territory sales forecast for SCE, rather than a Planning Area. Our adjusted Mid baseline scenario grows at about .9 percent a year over the forecast period, and then adding in the additional achievable energy efficiency, which ranges from 5,750 gigawatt hours to 15,200 gigawatt hours, this brings the annual growth rate down to .4 percent, .05 percent, and -.5 percent.

Okay, again, pairing low demand with high energy efficiency and vice versa, we have the High baseline scenario with the low EE growing at .93 percent, which is about the same rate as the unadjusted Mid baseline scenario, and then the low baseline paired with the high energy efficiency declines at a rate of -1.13 percent.

Okay, moving on to adjusted peak

scenarios, the unadjusted baseline here grows at a rate of 1.23 percent, unadjusted Mid, and the Additional Achievable Energy Efficiency (AAEE) Mid adjustments then bring the growth down to .67, .34, or -.27 percent.

And then combining Low with High, the High case paired with Low EE grows at 1.2 percent annually, and the low case paired with high energy efficiency grows at =1.06 percent.

And I've included in this presentation just a couple of slides for Southern California Gas. So just looking at the service territory sales forecast adjusted with the Additional Energy Efficiency, the result is that our relatively flat baseline forecast becomes a declining managed forecast growth in the adjusted scenarios here are -.25, -.35, and -.42 percent. And then pairing the Low demand with High Energy Efficiency gives us a growth of -.56 percent, whereas the higher case is actually not going up much higher than the Mid at -.31 percent.

And so I would ask if -- well, maybe I'll just invite Edison first to come up and give comments.

COMMISSIONER MCALLISTER: Maybe we can go ahead and kind of get going while they load those up; we're a little bit short on time.

MS. SHENG: Sure. Hougyan Sheng from Southern California Edison. I'd like to thank the Commission for providing this opportunity for us to comment. It's been a nice journey working with Chris Kavalec and his forecasting team to look into the forecasting issues. We also had the opportunity to work with CAISO this time, so it was quite a learning experience for us, so we appreciate that.

I'd like to compliment the CEC forecasting team in terms of being able to incorporate the earlier feedback we expressed with the earlier workshop. One great example is, you know, the updated rate forecast that gets incorporated in the revised forecast. I think that's very encouraging to us that CEC is looking more closely at the rate impact and taking more consideration of the changes.

I'd also like to compliment the fact that with the energy efficiency savings estimating development, we were allowed to engage in the process in terms of commenting on these scenarios. I think SCE would like to see more engagement from the stakeholders in the future in terms of working with CEC to develop the initial scenarios for later selection purposes.

And I think there are two areas we would like to address hopefully before the final forecast is generated. One other area is electric load forecast updates, and we heard from the team earlier that they're still working diligently on updating the electrification load forecast; we think that's a very important area, as well as a significant source for the future load growth. So SCE would certainly encourage CEC to prioritize that and hopefully be able to incorporate that in their final demand forecast.

But we would also like to point out that SCE has commented earlier after the Transportation Workshop that, from SCE's perspective, there is quite some uncertainty in terms of the future EV load growth. SCE would like to see the CEC utilize a range forecast potentially including CARB's ZEV forecast as a Low bound forecast, and at the same time looking at incorporating a higher case forecast, as we think that would give us a more comprehensive picture for the future.

And so the second area I would like to highlight is we identified some issues in the area of weather normalization after historical load, which affects the forecasting period, especially with the starting point for 2013 peak. We conducted some investigation with support from Chris Kavalec and CAISO planners. We had, you know, interesting findings I'll share with everybody on the Web, but one thing we recognize is, if you can go to the next slide? As time elapsed, we realized that our forecast period which starts from 2013 in the initial forecast, because the weather normalization impact, CEC's forecast for SCE Planning Area peaked for 2013, actually shows some slight decrease from 2012 peak to 2013; now, because time elapsed, we actually observed hopefully a summer peak for 2013 and the dashed line shows that if we were to utilize the updated 2013 peak number, the CEC's peak demand baseline projection would actually come a lot closer to SCE's view. So we definitely would encourage CEC to make that into their final forecast consideration by utilizing the latest data observation. If you could go to the next?

So as I mentioned, CEC and CAISO actually worked very collectively with SCE to investigate the weather normalization issue. Through our findings so far, I think we were able to see in common that our use of weather stations, and weights, and the way we calculate the peak factor temperatures, it all may matter for how we assess our peak day temperature conditions and, as a result, our forecast could be impacted as well. So SCE would like to recommend that the CEC look in the future initiative to include this initiative about getting all the stakeholders engaging in the weather normalization discussion and address the common forecasting issues around it to create more commonality among the different forecasting practices. And I think SCE views that the existing DAWG forum would be a great platform for that to happen. That's SCE's comments.

COMMISSIONER MCALLISTER: Could I just ask, how would that interact with the idea of sort of one in 10 and if we're weather normalizing, because I'm not quite clear on the benefit that you see it, if we're already coming at it from a one in 10 kind of perspective, you know, sort of risk mitigation and that way, you do get a better answer in some sense with weather normalization, but I guess I'm wondering what sort of practical impact you think that might have on your planning, your investment, things like that.

MS. SHENG: Yeah, as Chris mentioned in part of his presentation, when we look at the historical peaks, you know, we try to understand under what weather conditions those peaks occur. And depending on how we view the peak temperature conditions, we may view the history differently, and that will impact how we forecast the future, whether we assume the future is normal weather condition or is under some extreme weather condition.

COMMISSIONER MCALLISTER: So I think I understand what you're saying, but the weather normalization -- like if you had a peak that was a true peak, but was not driven by weather, then that would tell you something; and vice versa, if the weather drives it, then that also helps you make decisions.

MS. SHENG: Yeah. If we had a really

mild day, however, we still reached a very high system peak, that would be really affecting how we would project the future peak load growth. So in our view it's a common foundation for the forecasting practice, how we reconcile the history.

CHAIRMAN WEISENMILLER: Okay. I had a couple of questions, one just following up on that, what sort of weather year was this year, assuming we had the October peak or something dramatic?

MS. SHENG: We haven't done the complete preliminary assessment. I think this year our peak day condition was still below normal.

CHAIRMAN WEISENMILLER: Okay, so less than one or two.

MS. SHENG: Right.

CHAIRMAN WEISENMILLER: Okay. Now, Nick, could you go to slide 5 for a second? I'll ask the same question of both of you. Slide 5 is the one that shows consumption growth by climate zone.

MR. FUGATE: Which forecast?

CHAIRMAN WEISENMILLER: For Edison.

MR. FUGATE: I'm looking at the wrong

territory here.

CHAIRMAN WEISENMILLER: Okay, so you're seeing the highest growth occurs inland and from time to time, I visit different chambers in the Los Angeles area, and normally when I go inland, the chambers are pretty devastated, so I'm trying to understand in terms of where Edison's projections of growth are, is it really still inland? I mean, as I said, the economy seemed to have been hammered inland, so do you see that springing back? Or what is your projections of where the growth is going to occur?

MS. SHENG: At this point, SCE is not able to give a full assessment of the climate zone level impact because we have not developed a climate zone level analysis. We are seeing some shift in terms of economic growth between inland areas and closer areas, accounting to the most recent UCLA Edison School Forecast Update. There's, you know, the phenomena of east and west division, so until we can do a full assessment like CEC did in looking at climate zone level forecast, it would be difficult for us to come up with a complete assessment in terms of whether we will see the energy consumption pattern change due to the economic growth pattern change in the future.

CHAIRMAN WEISENMILLER: Okay, well certainly if you have anything on that, your written comments would be good because, obviously, to the extent we're seeing much more of the growth inland, then that tends to be the higher consumption areas, and as I say, conversely, when you just drive around there and meet with people, it seems like that inland is where the economic recession has had the highest impacts.

MS. SHENG: Right, right, definitely economically-wise, yeah.

CHAIRMAN WEISENMILLER: Another question I have is in terms of trying to understand, you know, it's back to the weather normalization issue, and one of the things we're trying to do going forward is to really monitor what's going on in the areas in the San Onofre footprint so we could see how the preferred resources are coming along and deal with contingency plans. And so, as we do that, it's going to be very important for us to figure out a way to disaggregate that part of your service territory, track what's going on, which could be weather, so we're going to need to make sure that we are weather normalizing; it could be the economy; it could be more or less development than expected of the preferred resources. So it's going to be very important going forward that we have a way of really tracking what's going on in that disaggregated part, and it's going to be a challenge to our staff, the ISO, PUC, and certainly for Edison to help us on that.

MS. SHENG: Yeah, I definitely agree. I think looking at an even more granular level like that, you know, one of the areas we need to establish a more common perspective is the weather, normalize the weather in the local area.

CHAIRMAN WEISENMILLER: Right, because we're certainly at least going to have to deal with the weather, but we may also have to worry about some of the economic growth, but frankly if the economic growth is more or less than we anticipate, you know, we'll still have to respond to that in the supply and demand balance, you know, one way or another.

I guess the last thing is just, obviously we've looked at the Port electrification and the other thing is sort of obviously to look on the goods movement side, particularly in the Port area to try to deal with electrifying the transportation system. So, again, anything you can do to help us on the EV forecast would be terrific.

MS. SHENG: Sure. I think SCE had already worked some effort in working closely with the Transportation Study Group at CEC, so we'd like to see that collaboration continue to go on and hopefully be able to push the updated forecasting to the final forecast that Chris is going to put out later.

CHAIRMAN WEISENMILLER: Yeah. I'm assuming Edison is really, well, we've heard different things. I think a while back the theory was SDG&E was really exposed to growth happening in EV, but my impression is it's much more Edison at this stage.

MS. SHENG: Yeah, definitely in the recent years.

CHAIRMAN WEISENMILLER: Okay, thanks.

MS. SHENG: Thank you.

COMMISSIONER MCALLISTER: I wanted to just follow-up quickly on a point, this information and disaggregation point that Chair Weisenmiller made. So I guess there are a number of efforts going on to utilize various types of data and at various levels of aggregation, and I wanted to know whether sort of there's one at UCLA, there's some work going on at different places in UCLA with different kinds of perspectives on this. There are lots of people who want to do that kind of work, including the County and the City of L.A., I think UCLA has been collaborating well with LADWP on getting some other data within the City for Zip Plus Four, the Zip Code level data for energy consumption. I'm wondering, well, I think it's actually really important and I'm wondering how much of that Edison is sort of doing, whether it's on your own, whether it's shared with local governments, whether it's sort of a partnership with the other entities, or pretty much in-house. And the reason I ask is because, exactly, the question that Chair Weisenmiller was pushing on is, we have to know what's happening over time and be able to look at other factors, weather and many many others, that we may not even anticipate today, but that we're going to want to consider in the future. And I think it's important to have a pretty broad discussion about this and not hold it too close.

MS. SHENG: I think this is a very good point. SCE would definitely like to collaborate with all the state agencies as much as we can. I think we believe, you know, transparent forecasting process would give us more reasonable basis to look at for the future, so be happy to work with Chris' team more closely in terms of bringing the different perspective together in the future.

COMMISSIONER MCALLISTER: Okay, thank you.

MR. FUGATE: Okay, and so my last presentation today will cover the PG&E Planning Area. Here, our Baseline Consumption Forecast for the PG&E Planning Area, these scenarios are higher than what we presented in May by about 3,300 gigawatt hours in the Mid case, which means that the revised Mid case is growing faster by a couple tenths of a percent.

High Speed Rail is expected to contribute 162 gigawatt hours, and Port electrification will add another 7,108 gigawatt hours. Electric Vehicles are in the neighborhood of 2,000 gigawatt hours in the Mid case, and climate change accounts for an additional 457 to 574 gigawatt hours in the Mid and High cases.

All of this amounts to a Mid scenario that grows at 1.2 percent annually to reach 123,460 gigawatt hours by the end of the forecast period. And one adjustment that is unique to PG&E territory and that we'll have to correct for the final forecast is that we found an error in our QFER history for PG&E, so correcting this will raise the consumption in the base year by 2,200 gigawatt hours.

So peak demand grows at a rate of 1.4 percent annually to reach 25,450 megawatts in the Mid case; self-generation is expected to contribute 2,000 megawatts, 1,000 of which is PV; Electric Vehicles only 50, and 120 megawatts. The combined impact from demand response programs reaches 125 megawatts. And climate change represents 377 and 569 megawatts for Mid and High.

So PG&E has five climate zones, it's the purple section shown here. Climate Zones 2 and 3 are the inland areas covering Sacramento and San Joaquin Valleys. Climate Zone 5 represents most of the Bay Area, San Francisco, Oakland, and Marin. And the rest of the coast is covered by Climate Zones 1 and 4.

And so we see a similar story here, the fastest growth in consumption and peak is inland in Climate Zones 2 and 3, and it's, again, that expectation that migration from coastal to inland areas will pick up again, growth and population from 2013 to 2024, and then Mid in that case is projected to be 21 and 23 percent in Climate Zones 2 and 3, compared to eight and four for Climate Zones 4 and 5.

And the same could be said about peak growth, particularly in the Mid case, growth is greatest in the inland areas, and potential climate change impacts again contribute to peak demand growth in Climate Zone 3.

Back to looking at the impact of Additional Achievable Energy Efficiency; on our forecast of sales for the PG&E service territory, our unadjusted Mid scenario grows at

1.07 percent annually over the forecast period, adding in the Mid AAEE scenarios which range from 5,500, 62 gigawatt hours to 14,646 gigawatt hours, brings the annual growth rate down to .56 percent, .21 percent, and then on the low case, .33 percent.

So pairing low baseline sales with high energy efficiency gives us a growth rate of just over one percent a year, which is close to our unadjusted baseline forecast, and in the lower case declines at a rate of -.9 percent.

So here are the results for adjusted peak and adjusted Mid baseline forecast grows at 1.56 percent, and then the mid adjustments bring the growth down to 1.0 percent, .64 percent, and then in the low case here it's actually flat.

And then here the High demand paired with the Low Efficiency gives the growth of 1.48 percent annually, and the Low demand paired with High Energy Efficiency gives -.68 percent annual growth.

And so that's all I have. If PG&E wanted to come up?

MS. CONNOLLY: Well, I'd like to thank the Commission for the opportunity to provide verbal comments. My name is Ipek Connolly and I lead the Load Forecasting Group at PG&E.

I want to start by commending the staff for producing such a comprehensive and well thought out California Energy Demand Report with revised results taking into account the comments that were provided by various stakeholders earlier. I want to commend the staff for also making major significant improvements to the Demand Forecasts, including but not limited to the expanded portfolio of both econometric models, as well as the new industrial model, incorporating climate change scenarios on energy, as well as peak demand, updating the Electric Rate Forecast, which were pointed out earlier, and incorporating energy efficiency forecasts beyond the first two years of the forecast horizon. In that regard, I would like to reiterate the desire to end up with one planning forecast that can be used as the California Energy Demand Forecast, recognizing that having the scenarios is extremely useful because it recognizes the uncertainty associated with these forecasts; but at the end of the day, we're all striving to work towards, you know, most likely expected energy demand forecast.

In terms of what we see in the report and the presentations today, we're in agreement with the baseline results. We're still reviewing the other elements of this forecast. There is a lot of detail, a lot of in-depth analysis, and there's a lot of updates based on good research, so we would like to take a little time to review them thorough, and then get back to you with our written comments. I also want to add that it would be great if we could see the Electric Vehicle forecast incorporated into the overall projections.

So with that, if you have any questions I would like to answer your questions, these are my comments for today.

CHAIRMAN WEISENMILLER: Yeah, I was trying to understand if -- we've talked about the electric forecast -- I don't know if PG&E and the staff have any comments on the natural gas forecast?

MS. CONNOLLY: Again, we didn't review the natural gas forecast. It's in general very consistent with our overall view of the natural gas demand forecast. Again, we're looking at some of the details, but I haven't spotted anything that required mentioning at this point.

CHAIRMAN WEISENMILLER: Okay, and in terms of -- do you have anything that you could submit to us on what PG&E's Electric Vehicle forecast is?

MS. CONNOLLY: I can certainly look and get back to you on that. Our forecasting cycle is a little behind, so we completed our forecasts, we're looking to get into our new forecasting cycle, so I'm sure there's a lot of information that's kind of being looked at, it's just not something that I have right in front of me today, but I can certainly look into that because we do realize there's an interest among all parties involved to see what the views are, so I'll definitely see if we can present something to you.

CHAIRMAN WEISENMILLER: Okay, thank you.

COMMISSIONER MCALLISTER: Just a quick question. Do you have an opinion about which of the efficiency scenarios you would like to see adopted, or tweaked, or any feedback on any of those? You sort of made the pitch for having one forecast, and I'm wondering which forecast, you know, within that, which of the efficiency scenarios do you think PG&E is either most likely to get, or at least would like in a forecast?

MS. CONNOLLY: Again, the Navigant study just came out, so we're looking into it and I'm not aware of a position or an assessment of results at this point.

CHAIRMAN WEISENMILLER: Well, I was going to say, having worked at PG&E, or with PG&E, I assume there's a difference between the technical forecasting position and Management's policy position, and your original statement was on the technical forecasting part, as opposed to a Management perspective.

MS. CONNOLLY: You probably have more experience than I.

CHAIRMAN WEISENMILLER: Yeah, I've been on the 32nd floor. My current key may still work there.

COMMISSIONER MCALLISTER: We can help, right? I mean, you know. Thanks very much.

MS. RAITT: Our next speaker is Malachi Weng-Gutierrez.

MR. WENG-GUTIERREZ: Good afternoon. My

name is Malachi Weng-Gutierrez. I'm going to be quickly going through a brief set of slides on LADWP's Planning Area.

First off, I just wanted to show a comparison between the Revised and the Preliminary Demand Forecasts. You'll note that the Electricity Demand increased in all three of the scenarios, partially due to the change and revision to the electricity rates, but also because we did add additional demand growth that has been mentioned for Ports. So you can see that it's increased over a percent in each of the cases. And that increase is also seen in the peak demands, as well.

So overall electricity consumption for LADWP again increased pretty significantly from .6 percent to 1.4 percent in the Low and the High cases. Obviously, the Low and the Mid are lower than the CED 2011 values and the High case increases above the CED 2011 value after about 2015. Part of that growth again is different Port electrification, as well as the EV demand numbers.

For the self-gen, this includes about 295 gigawatt hours in the Mid case; of that, PV represents 122 gigawatt hours, again in the Mid case, and then there are about 4,500 gigawatt hours of initial savings projected from 2012 to 2024 there included in the Mid case.

The self-gen contributes about 41 megawatt hours in the Mid case and about 24 megawatt hours of that is PV in the Mid case; growth rates here are fairly wide ranging, about one percent difference between the High and the Low, and all of which are below the CED 2011 Mid case.

LADWP is comprised of two climate zones, climate zones 11 and 12, and much like the CED 2011 forecast, the climate zone 12 demand growth is higher than the climate zone 11, which again, since it's an inland and it's in a different climate zone, obviously it's going to be influenced by temperature a little bit more extensively. And so I think that plays in the amount of both peak and total consumption growth that is observed in all of the three different cases that we have.

Then I just wanted to quickly show a breakout of the load growth that is attributed to the plug-in electric vehicle forecast. On average, each of these three cases grow in exceedance of 40 percent per year, that's pretty substantial growth for EVs. These again are the CED 2011 values that we're using in here, so the Low case here represents a ZEV compliant case; the High case here has a significant amount of PHEV growth in exceedance of the ZEV mandate, and then the Mid case is just the average of the two. And obviously you can see that in the High case, you have an addition of over 1,000 gigawatt hours in 2024.

Likewise, I wanted to show the Port electrification and how much consumption is attributed to that, not nearly as extensive as the EV load, but there are a variety of potential load growths associated with the Ports. You notice the tiered aspects of this and, as Chris mentioned in his presentation for the state, the regulations that ARB has in place have three compliance phases, the last of which is in 80 percent of all visits, as well as 80 percent of all on board consumption have to be electrified, and so even the highest -- or after 2020 you see the highest amount of electricity load from Port electrification. And again, Chris had mentioned that in the Low case, we pretty much kept the load growth flat, and then there are additional visits that are attributed to both commodity growth and other growth with -- container ships basically have load growths that are tied to commodity growth, and then we have cruise liners which have load growth tied to passenger growth rates. And so that's where we get the variation between the three different cases. And again, in the high case, we see a load growth addition of about 100 gigawatt hours. And I think that's it for my slides for LADWP. So I'm not sure if we're going to have anyone speak from LADWP, commenting on this -- maybe online? So again, I don't think -- they weren't going to come, but I didn't know if they were going to be online to make comments, so with that, if you have any questions?

CHAIRMAN WEISENMILLER: Well, I certainly would encourage your written comments so we have the benefit of that and certainly, again, their EV stuff as we're trying to pull that together, it would be good to get any forecasts they have on that and the basis for it.

MR. WENG-GUTIERREZ: Okay, well, I can

certainly touch base with them and see what EV forecasts they might have and either provide that to Fuels and Transportation or work with staff in figuring out how to incorporate that.

CHAIRMAN WEISENMILLER: That's great.

COMMISSIONER MCALLISTER: And Malachi, one question. So it looks like based on the 2011 final Mid, the load factors were actually better in DWP than anticipated in that the capacities -- all of our scenarios for this time around are lower on the capacity side, but not as much on the energy side? Any particular effort that resulted in that? Or is it just sort of the way things played out, or what?

MR. WENG-GUTIERREZ: I would say that that's just the way things played out. But we could certainly check into that, the specifics as to why that happened, and get back to you on that.

COMMISSIONER MCALLISTER: That would be great, a little bit of insight because the capacity in your slide 5, you know, the 2011 final Mid capacity is above all the other, all the current assessments that we've got, all three scenarios. The same is not the case on energy, so at some point you've got a better utilization of that then what was projected two years ago.

MR. WENG-GUTIERREZ: Yeah, we'll look into it and see why that --

COMMISSIONER MCALLISTER: Great, thanks. Let's move on to SMUD.

MR. WENG-GUTIERREZ: So if there are no further questions -- so Nate said he would be here at 3:30, so I may speak a little slowly. For my few slides that I have for SMUD --

COMMISSIONER MCALLISTER: We do have a SMUD representative here --

MR. WENG-GUTIERREZ: Okay, well maybe they could come and speak up here to comment, but I'll just go through the slides and maybe he will show up in time. So again, I'm just going to go through SMUD's planning area and, again, I'm going to start out with just showing the Revised and Preliminary Demand Forecasts and the difference between the two.

As you would imagine, again, the revised numbers are higher partially due to the rates and also, well, primarily due to the rates that we're showing for them. And again, here almost all of the growths are about two percent overall and the difference between the preliminary and the revised are above two percent in almost all the cases.

Likewise, the peak forecast is higher, as well and, again, I think primarily because of the change in the rates. So for the Demand numbers in all three cases we're starting out slightly lower than the CD 2011 values. The high case obviously grows to be above the CD 2011 values. And in general, you know, we have energy savings incorporated into this, about 1,800 gigawatt hours from 2012 to 2024. Self-gen, we have a total number of gigawatt hours of 219, 218 of which are from PV, and I think that's it for consumption.

The planning area peak, again, is only exceeded in the High case for the CED 2013, and the Low, I believe that nearly half a percent of the growth in peak -- the minted case is about half a percent over the preliminary forecast. And the peak here reaches a level of about 70 -- or, sorry, 3,700 megawatt hours in 2024 for the high case.

Again, breaking out the EV loads from all the others, again, we have the three cases, the Low case again being the ZEV mandated value, the share of which we're attributing to SMUD in the ZEV compliance scenario. The High obviously is again the case where we have a substantial amount of PHEVs entering the marketplace, and the MID is between the two. For SMUD, we show a total growth of over 160 in the High case. And SMUD doesn't have any Ports that we've included as far as the adverse (ph) regulations. So that's the end of my slides. So if you have any questions, I'd be happy to answer them.

COMMISSIONER MCALLISTER: Okay, so Malachi, could you discuss a little bit, you know, sort of knowing the difference between the Preliminary and the current has most to do with rates, and I guess is that the same kind of dynamic that happened with the investor-owned utility projections, sort of the preliminary to now? Is that the same underlying dynamic? I guess I'm wondering how you sort of did that analysis for the POUs versus the IOUs, if there was a difference there.

MR. WENG-GUTIERREZ: Yeah, so the increase should be partially due to the rates, but these are just the total of all the elements that are added, it's just that in some of the other cases we had things that were added like Port electrification, which were not in Preliminary, so you could attribute part of that growth to those.

For SMUD, we didn't have Port electrification. The EVs were already included, so the primary thing that was driving the change in my mind were the rate changes.

COMMISSIONER MCALLISTER: So they're the same underlying dynamics with natural gas projections and all that kind of stuff.

MR. WENG-GUTIERREZ: Yes. But again, because of the differences between the difference utilities and what we've included, I mean, there might be some balances to that.

COMMISSIONER MCALLISTER: Yeah, okay. So is SMUD going to electrify their Port?

MR. WENG-GUTIERREZ: Well, they may be electrifying, but they're not required under the At-Berth Regulation for ARB to electrify their Ports.

COMMISSIONER MCALLISTER: Okay, great. Do you have any questions?

CHAIRMAN WEISENMILLER: And I guess the other thing they're electrifying is light rail.

MR. WENG-GUTIERREZ: Right.

CHAIRMAN WEISENMILLER: I think we're good.

MR. WENG-GUTIERREZ: So I don't see Nate, so I'm guessing --

CHAIRMAN WEISENMILLER: He may come into the public comment.

MR. WENG-GUTIERREZ: Okay.

MS. RAITT: So I don't know if anyone is interested in making public comments?

CHAIRMAN WEISENMILLER: There he is. All right.

COMMISSIONER MCALLISTER: Do you want to know what Malachi said about you?

MR. WENG-GUTIERREZ: Okay, so I will hand the mic over to Nate Toyama from SMUD to go through his presentation, commenting on the items.

MR. TOYAMA: Nate Toyama from SMUD. Okay, three things on the agenda for me, one is an update of our forecasts, some other issues that SMUD has been working on, the second are actually the comparisons of the forecasts that we received I guess yesterday afternoon, so let's go to the updates.

In the initial filing, we didn't have a rate forecast to present to the CEC and that was because SMUD was going through a rate process or what we call a General Manager's Report and Recommendations on Rates and Services, very similar to a base case or a GRC that the IOUs go through. Since then, it's been adopted by the Board on August 15th, a couple months ago. The main part of the rate case, well, there are two parts to the rate case, one of course was the general rate increase of 2.5 percent in 2014, and again in 2015. The main component of this particular rate case, however, was the restructuring of the rates, and in this particular rate case there was a focus on both residential and small commercial. And what happened was, in the restructuring what was adopted was a plan in which SMUD would shift revenues from the energy or the volumetric charges to the fixe charges, and so you see fixed charges going up, or what they call the infrastructure charge will be going up in the next couple years. Rates themselves will go up, as well, but not as much as they would have been under a 2.5 percent rate increase.

The second component, or the second issue I'd like to talk about, is the 2014 -- our forecast update. Every winter before the budget, SMUD produces a new forecast. What I'm going to present today is the forecast that was actually presented in the April 15th filing. Just so that everyone knows what's going on, if you happen to see another SMUD forecast which should be released either in November or December, it will be somewhat different from the forecast that you see that was submitted April 15th. These are the forecasts that will be presented to the WECC and to FERC for various regulatory filings, and so you'll see that next year.

And so what we have this year, of course, is actually a combination of different forecasts just because of the timing that was involved in presenting the April 15th forecast, it has some of our December 2012 forecasts and some updates, and the updates are primarily with EE and EV and with PV, and so you'll see that in the filing that was submitted on April 15th.

The comments I have on the forecast -- let me just give you a preview of what we're actually going to talk about -- I tried to find a common ground on which to discuss the different forecasts, and this particular presentation will be reviewing the sales forecasts from the Form 1.1b Mid case from the update that was given to us yesterday. The Peak forecast will be the Net Peak Demand Forecast, which was Form 1.4 Mid Case. I'm going to compare those to SMUD's forecast, which were given in the 4/15/2013 submittal. I had to make some modifications to extend the forecast to 2024, but initially they're all fairly consistent with what was presented earlier.

And now for the comparisons. From this chart you can tell that our forecast, which has been adjusted for both PV and EVs, which should be similar to the CEC total sales forecast, are basically the same. There's very little difference, there's about a one percent difference going forward, and so given that we have really two separate models coming up with very similar results is to some degree very encouraging, very satisfying.

The bottom line, however, is what we would refer to as our managed case, and in that managed case we include SMUD's energy efficiency program. As many of you probably know, our energy efficiency annual goals are about 1.5 percent of our sales, or our unmanaged sales; it's a fairly aggressive goal, but if we keep to it and achieve it, then you'll see that we have the bottom line for our forecasted sales, which is essentially flat.

Now, I don't know if you presented the potential forecast for SMUD like you were doing for the other IOUs -- okay -- there was a potential study done for SMUD by Navigant, I believe, and so we have that data, we just haven't been able to really evaluate the data yet, so maybe we can work with you to see how you came up with those nifty crafts that you showed.

And so on the sales side, you know, we're pretty okay, we're cool. The next forecast, however, is different, and that's the Peak Forecast. And this is where we see really a fairly high difference between the CEC forecast and what SMUD is using for its planning purposes. The blue line which is much higher, roughly about four to five percent above the red line, which is our forecast with no EE, the green line, or whatever that lower line is, our forecast with EE, and that's roughly about 10 percent on the average difference between our forecast and the net demand forecast that was given to the CEC.

And so why do we think it's different? Or why do we think that our forecast is perhaps more plausible? We didn't go through some heavy duty statistical analysis, we're just going to present some basic metrics on how we evaluate our loads in the present versus what we would see in the future. This is a graph and what we did is I took the forecast that was presented by the CEC in their revised form, our forecast that was presented in the April 15th submittal; however, I used the CEC's projection of population, coming up with some sort of a numeral measure that we had in common. I couldn't find your accounts -- we typically use accounts, but I couldn't find accounts in any of your forecasts, so I used population which, you know, is fairly consistent with at least accounts.

And what I want to show on this particular forecast is where we were back in the height of the boom, where we are now during the recession, and as we slowly crawl out of the recession where we are. On the bottom line is temperature. When we forecast peaks, we typically have a weather normal year. And for our peak forecast, we used a degree of -- we used 106 degrees of the daily high, and that's what the bottom illustrates, the historical part as well as going forward, so it's 106 degrees following that three-day heat storm of 100, 104, 106, roughly about average temperature of about 87 degrees, which basically means that it's a 67 degree evening or early morning. And you can tell that, on the per person basis, that during the height of the boom and of course some very hot temperatures that we experienced between 2004 and 2008, that peak per person is very high. Coming out of the boom into the recession, we see that going down roughly to about 2.1 kW per person, and experiencing the same type of weather, not as high as what we experienced in the past, but still 106 degrees, which is what our normal temperature is, or where our planning temperature is. I don't know if that's normal, but it's what we used to plan.

The next slide basically tries to confirm what we established in our metrics, and that is to illustrate the most recent heat storm we experienced late June, early July. And during this heat storm, you can tell the loads -- in this load we never really got above 3,000 at the maximum, which was observed on July 3rd, we hit 3,014 megawatts. Now, to compare that with the CEC's forecast, I believe it's 3,140 megawatts, much higher than what we would ever expect to see given current conditions; now, it could change, we could go into another expansion like we saw during the 2004-2008 period, but given current conditions, we just don't see that happening and it was a good example of the late June, early July heat storm that tells us that our loads are still going to be pretty low. We look at it as a per account basis, which would mean it's about five kilowatts per account.

Now, the other thing about this heat storm is that this was an extremely rare heat storm. If you have to look at the heat storms over the last 130 years, we've never experienced a heat storm in this style. It was six days of over 105 degrees for each day. On the sixth day, of course, is when we hit our peak. On the seventh day, which would have been another record, an all time high for heat storms in Sacramento of above 105 degrees, we probably would have seen something much higher, maybe 3,100 megawatts, but of course that was the 4th of July, so we didn't see that. We typically look at holidays and sometimes on weekends as being about 200 megawatts lower than a weekday.

And so, given these conditions in which we still see a somewhat depressed economy, vacancy rates for retail and office space roughly still about 18-20 percent high. The vacancy rates for residential homes was still about seven percent, pretty constant over the last several years. The number of persons per household still relatively stable at about 2.7, I think, is what the CEC has, we have about 2.6, so still relatively stable numbers. We haven't seen much changes except that in the CEC's forecast, you predicted it to go a little bit higher next year, whereas ours is relatively stable, we expect more kids, if we're lucky to leave the home, leave their parents, rent their own apartment hopefully in mid-town, so -- anyway, the whole idea or the whole rationale for our forecast is that we still see a relatively depressed load.

Now, during the 2004-2008 period, we were sort of wondering what was going on with those, why was it so high, seeing about 5.15 kilowatts per account, 5.2 kilowatts in some cases, but now if we get five kilowatts per customer on a hot day, that's a pretty good peak.

And so what we see here is that 3,000 to us is pretty stable, pretty manageable peak, something that we're going to be planning for, for the next couple years.

Anyway, I think that's it. Any questions, I'll be glad to answer them.

COMMISSIONER MCALLISTER: Yeah. Thanks very much, that was super interesting. So I guess probably for both Commission staff and for you, I guess, you know, you have two curves on your presentation, one is the adjusted and one sort of includes the EE. What do you use those two curves for? You sort of imply that the higher of the two was for planning, and the lower was sort of maybe aspirational or something? I'm putting words in your mouth.

MR. TOYAMA: The high forecast that we present versus the lower forecast?

COMMISSIONER MCALLISTER: Well, for example, the energy side, the one that matches the CEC versus the one that includes aggressive energy efficiency, what do you use those two for?

MR. TOYAMA: Well, we use the -- for both the peak and sales, we use the managed forecast, or the one that includes EE, to determine our resource mix. If you look at our WECC filings or our FERC filings, we typically will use -- you'll always see energy efficiency as our resource just like PV is a resource, or PV and EE are both considered resources, and so on our planning we'll plan to meet with other resources, both lower lines, and that's how we manage our portfolio, that's how we measure our budget, that's how we calculate sales, and so --

COMMISSIONER MCALLISTER: What about investments in your grid infrastructure?

MR. TOYAMA: I'm sorry?

COMMISSIONER MCALLISTER: What about investments in grid infrastructure?

MR. TOYAMA: I can't hear you with all the cackle going.

COMMISSIONER MCALLISTER: Sorry. Which of those curves do you use for sort of distribution planning and things like that?

MR. TOYAMA: For what type of planning?

COMMISSIONER MCALLISTER: Distribution system planning in investment.

MR. TOYAMA: Distribution planning is sort of a different type of forecast. We typically -- for distribution planning, we don't typically look at loads -- well, we do look at loads, obviously, but we're more concerned about looking at the number of customers because, for distribution planning, at least at the secondary level, that's what we're going to basically have to serve.

COMMISSIONER MCALLISTER: Okay.

MR. TOYAMA: Now, going at the higher level of distribution either at the primary or at the 115, or at the 169 kV, we will look at the load impact because we're looking at diversified loads and when we plan for those higher levels of distribution, we're typically looking at a very diversified load. But at the lower level, at the secondary level, we're typically looking at the customer load and, given the number of customers which we're projecting for next year, which is roughly about 5,000 customers, we're going to plan accordingly with our distribution criteria, which is looking at the load per count or at the transformer level. And so that's how we would do distribution.

COMMISSIONER MCALLISTER: Okay. So I guess, have you had a dialogue with our staff about the difference in the sort of peaks and explaining that and picking it apart, or are we just kind of hearing the first of that from you?

MR. TOYOMA: Not that --

COMMISSIONER MCALLISTER: Okay, so we're just hearing the first of it now and it needs to be kind of --

MR. TOYAMA: I mentioned it last time, so I knew it was high last time too. But if I had to err, of course, I'd rather err on the high side than the low side, but it is for our purposes relatively high. It may be it's looking at two different eras, you know, it's really more consistent with the growth expansion that we saw in the 2004 to 2008 period.

COMMISSIONER MCALLISTER: Okay.

MR. TOYAMA: And that's when we saw very high loads on a per customer basis. But recently it's fairly low, so I think overall on the forecasts or on the methodologies, what you're planning for, what type of world are you planning for, and when we're doing our resource acquisition, which is really short term acquisition in terms of resource reliability or for reserves, we're looking at a short term acquisition, not building, we're looking at purchasing out the market --

COMMISSIONER MCALLISTER: So I guess, I appreciate that, I guess the question is, you know, do you think this is a temporary thing due to the economy, or do you think it's going to bounce back along the lines of what the Commission -- you know, back into the realm that the Commission has projected for demand, for peaks?

MR. TOYAMA: I would say for the near future it's a pretty good view of the world, our lower forecast. Of course, going forward, it's so hard to predict, but we're typically looking at -- for our forecast, we typically look at about five years at the maximum for at least resource acquisition. Now, for building other resources, we're going to go 20 years out. But typically what we do for other resources, we looked at different scenarios like the CEC has, we look at the one and two, which is primarily energy and capacity, but we look at the one in 10, which is going to give us another couple hundred megawatts to look at other types of distribution, or other types of resources which we refer to as our load serving capability. So it's really looking at under extreme conditions, and under various scenarios such as the contingency analysis, we have to know what we could build assuming that something is going to go out. And so we always have some room to sort of wiggle when we're looking at the load serving capability forecast, which is used for looking at transmission, is used for looking at bulk transmission, or we're looking at it for building capacity --

COMMISSIONER MCALLISTER: Okay.

MR. TOYAMA: -- for voltage and so forth.

COMMISSIONER MCALLISTER: Okay, got it.

MR. TOYAMA: It depends on the type of forecast that we're using. This particular forecast is basically our resource acquisition forecast.

COMMISSIONER MCALLISTER: Great. Thanks very much. So, Chris, did you want to make a comment?

MR. KAVALEC: Yeah, I just wanted to say that we sat down with Nate a couple months ago and compared peak forecast and what it basically came down to was our assumptions about what happens in the next couple years. We have for SMUD a relatively cool weather year in 2012, so our peak goes up from 2012, and then the recovery pushes the peak up farther. From that point on, the growth rates are very similar. Ours is a little higher because we include climate change impacts and SMUD doesn't. But aside from that, no one knows more about the SMUD service territory than Nate, so we're happy to sit down again and talk about the peak.

CHAIRMAN WEISENMILLER: That's great. I was going to note, I'm trying to remember what

SMUD official I met with, but after your sales actually dropped one year, you know, and the question was where things were going in the future. One situation you're in is obviously a lot of people had permitted projects in 2008 which they just parked, and so if the economy comes back, they can sort of move on those fast, but there does seem to be more construction going on at this stage around town, as opposed to a more typical year where you have to go through the permitting process to actually start moving things forward.

MR. TOYAMA: In terms of that question, you know, we don't see much of an increase in the new homes, we do see about -- I think this year we'll -- let me step back a bit -- we tend to look at permits, you know, permits are obviously the sort of milestone that we look at where builders are actually going to build something. And up until now we still see a relatively low level for mixed being pulled for building new units, whether they're single-family or multi-family homes. We do see an increase, however, from last year and the year before, but it's nowhere near the 12,000, 10,000 units that we were seeing built back in 2006. This year, we're lucky to see 2,000. And so, given that, we still think that the housing market is, at least for 2014, will be somewhat depressed. Actually, we're looking at about 4,000 new units in 2014. In '15, we see an expansion of about 6,000 to 8,000 going forward in 2015 to 2018. So we do see a recovery and we use the similar data that the CEC uses for their housing starts and their economics. But I think on the load part, the issue that we have is not residential has been fairly strong, it's really the commercial sector that we see most of the lag in. And from just looking at our data, we know that commercial units tend to lag about one year, both in terms of starts and both in terms of declines. And so we saw that the small commercial sector declined slowly after the residential sectors were declining back in '07, and then the commercial sector now has been relatively stagnant, and we expect to see that growth in 2015. But in terms of our planning, because we do this every single year, and in extreme cases we'll do it twice a year, that if things begin to turn around, we'll be able to see it and incorporate it into our forecast. So, once again, our forecast really is a short term forecast; we extend it to a long term, but it really is meant to look at a short term resource acquisitions and short term portfolio issues. And then it's carried out to the long term to look at other issues such as renewable portfolios, other goals that we have for energy efficiency and perhaps building either transmission, or generation, or some type of generation within SMUD service territory to provide both support, or peakers, or perhaps ancillary services. But because this exercise is done every year, it gives us a chance to look at the current trends and then extrapolate on the current trends.

CHAIRMAN WEISENMILLER: That's good, that helps. Actually one of our earliest first workshops in this whole effort, I don't know if it was the first, or one of the first, was on econ-demo, and we had Mike Rossi in, and in that meeting some of the builders were saying, you know, can California get back to the glory days of 250,000 new housing starts a year, and Mike saying, God Bless, I hope not, you know, we really have to build our economy on something that's more sustainable than subdivisions dotting the areas, building houses we don't need and can't afford. But, yeah, hopefully we've gone from our floor, whatever, 40,000 or 50,000, but it's hard to imagine going back to the boom days of 2008 with the housing bubble.

COMMISSIONER MCALLISTER: All right. Thanks. So we have another session of public comments?

MS. RAITT: So now we can open it up to public comments and start with the cards.

COMMISSIONER MCALLISTER: We have one. Bill Monsen. There he is.

MR. MONSEN: Chair Weisenmiller and Commissioner McAllister, I'm Bill Monsen, I'm representing IEP and I'm with MRW and Associates. And I appreciate the opportunity to give some comments on the really good work that I think the staff has done on the Additional Available Energy Efficiency, or whatever the thing is called these days.

I have a couple of -- first off, I agree that it makes good sense to present multiple Mid case scenarios that provides, I think, the decision makers and various parties good information about what the range is in sort of a Mid case, so I think that was a very good approach by the staff.

I have a couple of comments about the AAEE forecasts. The first is with regard to the impact of rate design on energy efficiency impacts. Given that it appears that residential rate design is going to be moving more toward having a fixed charge, as well as an energy charge, that could very well reduce the costs that are avoidable by energy efficiency, and that might tend to push downward the types of impacts that we've been seeing, and I don't believe that that two-part rate was included or modeled into that work, so that's something that I think your staff is going to want to look at maybe in the next go-round.

With regard to the emerging technologies, again, I think it's an important point to recognize the impacts associated with those emerging technologies, they're really one of the drivers in the range of the uncertainty in the Mid case forecast. And I guess IEP's position has been that it's going to be important to be conservative with regard to your forecasts, particularly since those forecasts may well be used for determining local levels of demand that will be used in determining local reliability and procurement.

The last point on the AAEE is that it's good to see that the Low Mid case was assuming a 1.0 total resource cost test threshold. Given that it appears that, at least with regard to Southern California Edison current request for offers, which is an all source solicitation, that providing -- essentially allowing non-cost-effective or energy efficiency programs that might not meet a 1.0 total resource cost test, I think that's going to be a real challenge or test as you move toward more of an all source solicitation program. So those are my AAEE comments.

With regard to the solar estimates, the behind-the-meter solar estimates, I think you're going to run into the same kind of issues that I talked about with regard to energy efficiency and rate design. To the degree that, again, residential customers are going to be facing a two-part rate, that's going to reduce the cost-effectiveness of behind-the-meter solar, so that's going to be something that's going to have to get picked up at some point down the road. And IEP will be happy to provide some comments on this.

COMMISSIONER MCALLISTER: Great. Thanks very much. That's all the blue cards. Do we have anyone on the phones or WebEx that wants to speak?

MS. RAITT: So we don't have anybody on WebEx, and so we'll open it up, we have a few phone lines we'll open up and I'll ask the folks on the phone to put their phones on mute unless they have a comment they'd like to make, or a question? So the phone lines are now open if you have a question.

MR. KRISTOV: Hello. This is Lorenzo Kristov with the ISO. Can you hear me?

MS. RAITT: Yes, we can. Thank you.

COMMISSIONER MCALLISTER: Yes, go ahead.

MR. KRISTOV: Okay, thank you. Good afternoon, Commissioners and my friends at the CEC. I just wanted to, for the ISO, chime in and concur with the comments made by Simon Baker of the PUC earlier today referring back to the work that staff at all three agencies have been doing over the last many weeks to follow through on the commitments made by the three agencies in response to Senator Padilla's hearing, particularly the point on interagency agreement on the forecast numbers that we want to use for planning and procurement processes coming up and, again, within that the specific focus he had on the Additional Achievable Energy Efficiency. As Simon pointed out, and we agree, we see the IEPR proceeding providing a record for -- and perhaps being the best vehicle to identify what those appropriate forecast numbers would be, and we plan to attend in person on the 15th at the next workshop, and we can discuss this in more detail; but I wanted to at least make that point for your consideration today.

CHAIRMAN WEISENMILLER: Okay. We want to make sure that you're speaking for Management.

MR. KRISTOV: Yes.

CHAIRMAN WEISENMILLER: We know staff speak on technical issues and we encourage that, but you better have Management position. Thanks.

MR. KRISTOV: Okay. And we will

certainly be ready to present that on the 15th.

COMMISSIONER MCALLISTER: Okay, thanks for that comment. Anybody else wanting to from the phones?

MS. RAITT: It doesn't sound like it.

COMMISSIONER MCALLISTER: All right, great. Well, except for an hour or so, I was waylaid and managed to get some relief and my newly stitched up son appreciates your forbearance, family emergency notwithstanding. And I really enjoyed today and, really, I think at the end, you know, the appreciation to staff and all the stakeholders that you have been able to engage with consistently over the last few months is really appreciated and I think extremely valuable to get the forecasts and the various utility territories sort of iterated and basically to a pretty close level of consensus, at least as far as we can reasonably expect to get, and that's quite an accomplishment, and I think it's really going to serve the state well regardless of the forum in which we might adopt or refuse. So I want to thank Chris and the team, Nick, Malachi, and all your counterparts for working on that so diligently. And I believe this is the last workshop we have explicitly about this topic, but there's still a little bit of work that will come out of today that will be incorporated into the final document, and go from there. So I want to thank everybody for coming and, you know, you're the stalwarts here at the end of the day on the last Forecast Workshop. So thanks again. I really appreciate it. I know the document is going to be a strong document this year, it's really shaping up nicely on the various topics that we've targeted. But every year, or every IEPR, the forecast is really a cornerstone of the document and I know the value of it for the state for the next couple years, and having that long term record every two years, you know, really does help build the foundation that not only the Energy Commission, but the other energy agencies build on year in and year out. So thanks again and I'll pass it over to the Chair.

CHAIRMAN WEISENMILLER: Yeah, I certainly want to thank people and certainly the staff for their hard work on the forecasting area and the contribution of the other agencies. Again, there's been a lot of very solid technical analysis done and giving us a strong record to move forward. So, thanks, and certainly looking forward -- again, certainly still time to do written comments and we're certainly looking forward to the written comments on the forecasting and certainly I'm sure Chris will be happy to work with people to try to help them digest what's been done and changed over time.

COMMISSIONER MCALLISTER: Great. Thanks very much and we're adjourned.

MS. RAITT: Thanks.

(Thereupon, the Workshop was adjourned at 4:08 p.m.)

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